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2002 - 2012 Electricity Outlook Report

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Executive Summary

This report assesses California's electricity system over the next ten years, focusing on supply and demand forecasts, reliability, wholesale spot market and retail prices, demand responsiveness, renewable generation initiatives, and environmental issues. Part I, Setting the Stage, includes background information to understand the electricity market developments over the last three years and a supply adequacy assessment for the next three years. Part II, California's Electricity Demand and Supply Balance, discusses how key uncertainties affect our ability to make longer-term forecasts of electricity demand, supply adequacy, and wholesale electricity prices. Part III, Issues Analyses, explores how the current state of the electricity market is affecting prospects for sustaining adequate generating capacity, retail electricity rates, the development of demand responsive loads and renewable generation, and the environmental review of proposed power plants.

Scope and Purpose

The *2002-2012 Electricity Outlook Report* is a product of the Energy Commission's ongoing responsibilities to evaluate California's electricity demand and supply and to assess electricity system issues. Its purpose is to provide the Governor and Legislature an assessment of the state's electricity system over the next ten years and information on issues impacting state electricity issues. In addition, the results of this report will be available within the timeframe needed to meet the Energy Commission's obligation, under Section 3369 of the Public Utilities Code, to coordinate with the California Consumer Power and Financing Authority's development of its Energy Resources Investment Plan. This obligation was enacted in Senate Bill Number 6X, which was signed into law by Governor Davis. (Stats. 2001, 1st Ex. Sess. 2000 - 2001, ch. 10.)

This study helps to inform generation and demand decisions that could be made within the next two years by analyzing their possible intended and unintended consequences through the rest of the decade. The study necessarily examines the entire West, but focuses on electricity market trends and issues within California.

This report provides analyses that will help identify the choices and constraints, alternatives, implications and proposed actions that will further the goal of balancing electricity system reliability, reasonable prices and environmental protection. To meet this goal in a sustainable fashion, the long-term impact on suppliers, consumers and the environment must be carefully considered. Based on current supply and demand assessments, the Energy Commission believes that the near-term outlook for supply adequacy is promising. This gives California breathing room to examine the opportunities and choices for meeting its environmental, efficiency, and renewable resource investment goals.

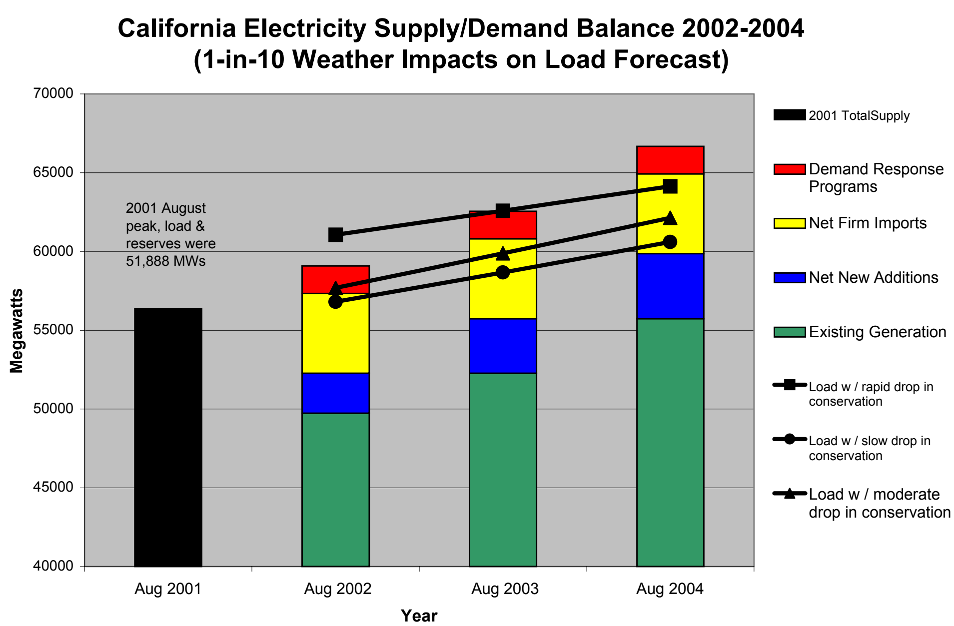
The remainder of this "Executive Summary" summarizes the analyses, findings and conclusions discussed in the report.

Part I: Electricity Market Developments - Setting the Stage

Part I summarizes the factors that have created the market volatility of the last several years and the events that have allowed the market to stabilize this summer. In addition, this chapter provides an electricity supply outlook of the expected near-term trends.

Based on the Commission's analysis, the electricity outlook for the next several years is more favorable for maintaining system reliability and moderating wholesale prices. **Figure ES-1** highlights the near-term capacity supply outlook. Although the outlook has improved for maintaining system reliability through 2004, several issues still need to be resolved. Many of the market structure changes made to avert the near-term crisis actually compromised some of the intended long-term goals of restructuring and have raised issues about the long-term sustainability of system reliability and moderate electricity prices.

Figure ES-1



The market structure that currently exists is an *ad hoc* arrangement, created to respond to the immediate needs of the crisis that was averted. If pending electricity related financial issues are not resolved and positive steps towards fixing the market structure are delayed, California will most likely face long-term system problems. Policy makers now have to choose what market organization and market structure will best serve California. What should the new market look like? Will it still have a strong competitive flavor or will the State assume a larger role in procuring future power supplies? Does the State need to have a "reserve," and if so, what form should it take and how large should it be? These questions need to be carefully analyzed and thoughtfully addressed.

Part II: California Electricity Demand and Supply Balance

This chapter presents the component analyses comprising the overall electricity supply and demand assessment for the next decade. Chapter II-1, California Electricity Demand, examines the uncertainties associated with forecasting the California electrical system peak demand and energy requirements, given the substantial reduction in consumer demand in response to the recent electricity crisis.

Chapter II-2, Energy Market Simulations, examines the uncertainties associated with forecasting energy spot market prices and new power plant completions under a variety of supply and demand scenarios. Even with much of the energy demand served under bilateral contracts, spot market prices remain an important price signal for developers of new supply- or demand-side electricity resources. The goal of this analysis is to estimate spot market prices, which can be used to assess the likelihood of additional capacity expansion and the retirement of existing power plants.

Chapter II-3, Putting the Risks of Capacity Shortages in Perspective, presents a probabilistic analysis of the potential risks that near-term (2003) capacity resources may be inadequate to meet demand and reserve requirements. This chapter's goal is to understand how robust is the more deterministic supply adequacy assessment found in Part I. This chapter also examines the differences in supply adequacy risks among the various transmission-constrained areas of the state (this was not a feature of the Part I supply assessment).

Chapter II-1: California Electricity Demand

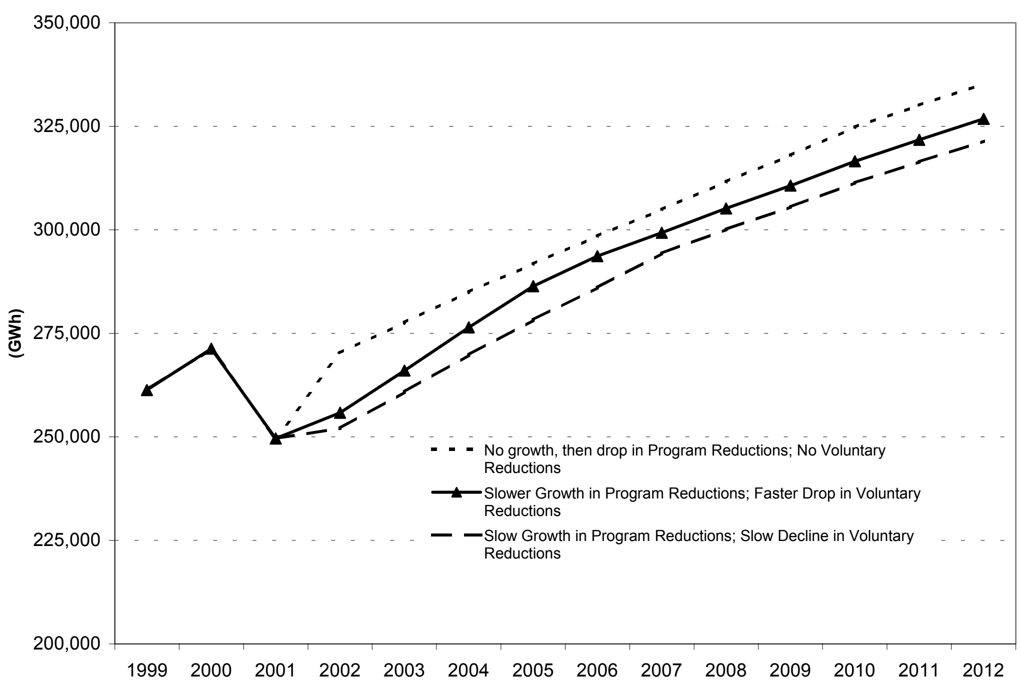
The summer of 2001 saw an extraordinary reduction in peak demand. Even though the summer of 2000 and 2001 were equally hot, actual summer peak demand in 2001 was substantially lower than in 2000. There were 29 days during the summer of 2000 when demand exceeded 40,000 MW. There were only 6 of these high demand days during the summer of 2001.

The following summarizes our analysis of expected California energy consumption over the coming decade:

- Uncertainty about future economic conditions makes forecasting highly uncertain.
- There is uncertainty regarding why summer of 2001 demand reductions occurred although electricity price increases, programs, and volunteerism are factors reducing summer 2001 demand.
- Impacts of demand reduction programs may increase slightly but, unless there are new campaigns or crises, voluntary demand reductions will likely decrease over time.
- The full impact of rate surcharges and newly legislated programs have not yet been seen.
- It is not clear what, if any, effect recent events will have on economic growth in the state — and on energy growth.

To capture this uncertainty about future electricity use, the Commission Staff developed several possible patterns of future trends for the persistence of summer 2001 demand reductions. These patterns are based on alternative assumptions about the level and persistence of voluntary impacts and permanent, program impacts (**Figure ES-2**). These three demand scenarios provide the demand forecast for the different analyses throughout this report.

Figure ES-2
California Electricity Consumption Scenarios



As well as detailed data about customer use, information is needed to determine why customers did what they did. Surveys need to be done to analyze how much of the reduction was due to customer behavioral and permanent response to legislated programs, how much was due to media campaigns, and how much to other factors. A better understanding of 2001 will reduce some of the uncertainty in the projections of future demand reduction.

Chapter II-2: Energy Market Simulations

This chapter presents five different scenarios simulating the wholesale spot market for electricity. The goal of this analysis is to obtain estimates of spot market prices, which can be used to assess the likelihood of additional capacity expansion (beyond what is already very likely to occur) and the retirement of existing power plants. The scenarios are differentiated by their assumptions about demand growth and new power plant additions during the next four years. The assumptions that characterize each scenario are discussed in detail. The simulation results are presented and discussed, including the spot market prices yielded by the five scenario simulations and the impact of power plant additions on the hours of operation of new combined cycles, peaking units, and the older and larger gas-fired plants. The chapter concludes with a discussion of the implications of the findings for the construction and retirement of capacity during the second half of the decade.

The long-term power contracts signed by the California Department of Water Resources to supply customers of the three largest investor-owned utilities, together with energy from utility-owned nuclear and hydroelectric generation and QF contracts, greatly reduce the share of energy to meet IOU customer demand purchased in spot markets. Accordingly, spot market electricity prices will play a significantly smaller role in determining the wholesale cost of energy for IOU customers. Spot market prices will continue, however, to have a major influence on the decisions to build new generation capacity and to retire existing facilities.

Low spot market prices, those that do not result in profits high enough to warrant investment in new plants, deter capacity expansion. If low enough, spot prices encourage the retirement of plants that cannot cover operating costs. High prices signal the need for new capacity and its profitability. Our results tend to indicate that the addition of expected new capacity during 2002 - 2005 is apt to drive spot market prices to levels that will render many existing power plants unprofitable and discourage further construction. However, there are factors that may encourage building even in the face of low prices in the short-term.

The simulation results also indicate that low prices from 2003 onward may be an incentive to retire existing units. It is unlikely, however, that a substantial amount of capacity will be completely retired and dismantled in the WSCC during 2002 – 2004. Uncertainties related to the amount of new capacity coming on-line, the return of electricity demand to previous trend levels, and regulation and market structure will contribute to uncertainty regarding spot market electricity prices, and discourage the closure of generation facilities. Owners are apt to incur the costs required to keep less-efficient plants available for operation given the *possibility* of adequate revenues during the next couple of years, if not long-run profitability. Low prices in 2003 and 2004, would lead to reduced operation for many plants. This reduction in their competitiveness will encourage their placement into long-term reserve, and increased consideration being given to their retirement

As gas-fired power plants become an increasingly large share of the generation resources in California and the WSCC, the price of natural gas will have an increasingly larger role in determining the spot market price of electricity.

Overbuilding and delays in retiring older facilities are part of a "boom-bust" dynamic that is an inherent part of the structure of the market. The amplitude and length of these cycles cannot be known in advance, but must be considered in market design.

Chapter II-3: Quantifying the Risk of Capacity Shortages

Generally, the power system is said to have adequate capacity if it has enough generation and transmission resources to meet the customer demand and to maintain a reserve of capacity for contingencies. But it would be prohibitively expensive to build an electric generation and transmission system that would *never* experience a service outage. Instead, we seek to minimize outages within a constraint of reasonable cost, thereby accepting some risk of outages.

The goal of this chapter is to understand how robust is the more deterministic supply adequacy assessment for 2003, found in Part I, by applying more probabilistic risk assessment techniques. In doing so, we illustrate the risk issues that are central to the questions: What risk of supply shortages are we facing in the near term? Do we have "enough" capacity? How much additional risk will the next increment of capacity avoid? What are our options for managing the risk, and how do their risk management performances compare? In addition, the risk assessment in this chapter examines the differences in supply adequacy risks among the various transmission-constrained areas of the state, which was not a feature of the previous supply assessments.

This chapter specifically illustrates how uncertainties associated with specific key risks that affect supply adequacy contribute to the overall risk of supply shortages. (By "shortage" we mean failing to maintain a seven-percent reserve;

we do not mean experiencing a service outage of firm load.) We assessed one demand-side risk to supply adequacy: the effect of temperature variations on peak demand. We assessed three supply-side risks: the effect of hydrological conditions on the availability of hydroelectric generation capacity, the effect of potential construction delays on the availability of new power plant capacity, and the effect of aging on the rates at which generation and transmission facilities are forced out of service. We selected the summer of 2003 as the time period to illustrate the risk assessment because the supply balance was tightest that year and sufficient time remains to take additional action, should that be warranted.

Generally we have found that our probabilistic risk assessment gives us a measure of confidence in the near-term supply adequacy outlook in Part I. Although this work does identify the *possibility* of shortages in excess of those identified in Part I, the probability of their occurrence is generally small. The risks of power supply shortages in 2003 vary for different parts of the state: from little to no risk for Northern and Central California and the largest municipal utilities- LADWP and SMUD, to low risk (about 1 percent) for Southern California, to a noticeable level of risk (7 percent) for San Diego, and to a significant level of risk (about 14 percent) for San Francisco.

Depending on the cost to society of such shortages, actions in addition to those anticipated in the Part I near-term supply analysis might be taken (and their associated expense incurred) to avoid the additional risk of shortages. A cost-benefit analysis of available "supply adequacy insurance" options has not been attempted in this report. However, we do make the case that, if supply adequacy insurance is sought, then the full range of demand- and supply-side options for mitigating that risk should be considered.

Part III: Issues Analyses

This part presents discussions and analyses of a variety of issues important to the development of a workable electricity market. Chapter III-1, Electricity Markets and Capacity Supply, deals with the fundamental question of how well the existing energy market can be expected to maintain the adequacy of the electricity system at reasonable prices, and what market changes might better achieve that goal. Chapter III-2, Retail Electricity Price Outlook, provides an assessment of future retail electricity rates by utility and customer class, showing how the various components of costs each contribute to the total rate. Chapter III-3, Developing Demand Responsive Loads, examines the characteristics of the demand response potential, and suggests a specific mix of load curtailment programs to ensure reliability in the year 2002. Chapter III-4, Effects of Renewable Generation Initiatives, discusses how recent events and the current *ad hoc* market arrangements have affected the renewable generation industry and issues related to incentive programs for developing renewable generation resources. Chapter III-5, Siting Issues, describes the progress the

Energy Commission has made in licensing new power plants, issues that may affect the ability of power plant developers to obtain timely approval; and measures needed to address these siting issues.

Chapter III-1: Electricity Markets and Capacity Supply

This chapter examines what structure will motivate the addition of timely new supply to reduce price volatility and contribute to reliable service. Three options for revising the supply market for capacity are introduced and evaluated. This chapter also finds that modifications to retail pricing and to the wholesale market are also necessary for a sustainable generation market. Unless modifications are made, by 2005 California will be headed back into supply and demand conditions likely to produce tight supplies, price volatility, reliability concerns, and consumer dissatisfaction.

Choosing a method to ensure future adequate supply is a major element of the 2002 market redesign. Tight capacity supplies were one of the principal conditions that allowed the California market to destabilize. The current market structure must be changed, because it cannot produce adequate generation in a timely and efficient manner. Under the current market structure California is doomed to boom and bust cycles, price spikes, price volatility, and higher prices due to the need to hedge against the risks inherent in a faulty market design. A good market design will provide benefits to consumers and suppliers, allow for efficient market monitoring, reduce the need for government intervention, and promote competitive innovation. Policy-makers now have to choose what market structures will best serve California.

Three supply designs are evaluated: incentive payments for reserves, installed capacity requirements and a regulated, cost-of-service capacity reserve. Of the three, the installed capacity requirement is the most promising. But its actual effectiveness is dependent on complicated implementation rules. Hundreds of millions of dollars are at stake in these design details. Further exploration is needed to determine the most effective capacity payment options

The wholesale and retail market structures are interdependent. Effective generation price signals cannot take place independent of price responsiveness in the retail market. Consumers must choose to consume or not consume based on prices that reflect market conditions. They may make this choice directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability.

Generation adequacy will be facilitated if the wholesale day-ahead, hour-ahead, and real time spot markets use commercial models that reflect physical constraints and efficient dispatch. Generators must have an obligation to perform according to schedules. Accurate locational prices are needed.

The market structure must be compatible with other market designs in the Western United States. California is an integral part of a regional market. A coherent market design will need to be advocated in multiple forums, including FERC, the ISO, CPUC, CPA, and DWR. New California laws will be needed to facilitate a new design.

Chapter III-2: Retail Electricity Price Outlook

This chapter presents the Energy Commission's outlook of electricity retail rates for California Investor- and Publicly-Owned Utilities for the years 2002-2012. In this outlook, the Commission provides estimates of the retail electricity rates that typical consumers may pay, given projected energy prices, utility plans and programs, and regulatory decisions. This outlook provides consumers, market participants, and policy makers with a basic understanding of the determinants of future electricity rates.

This outlook is not an absolute prediction of what the future electricity rates will be, since future regulatory actions, technology development, or market changes may alter key fundamental assumptions. Retail electricity rates detailed in this chapter reflect the best available information to Commission staff up to mid-November 2001 and a set of assumptions the authors believe probable and realistic. Since then, the California Public Utilities Commission has rendered some decisions that have a direct impact on the IOU price outlook. In addition, Southern California Edison provided comments and data to Commission staff that could also change the outlook. The Commission has directed the Staff to incorporate relevant data and information in an update of retail electricity prices within the next two months.

Under the circumstances specified in this chapter, retail rates for investor-owned utility (IOU) customers will most likely increase in the 2002-2003 period. A rate decrease is unlikely, unless the Federal Energy Regulatory Commission (FERC) orders merchant generators and energy traders to refund the State utilities for overcharges incurred during the fall 2000 and the winter 2001. However, a small rate decrease is possible after 2003 for most IOU customers. Municipal utilities are likely to maintain constant retail electricity rates for their customers during the 2002-2003 period. Rates for municipal customers after 2003 would most likely reflect the utilities' cost of generation, which under current projections will increase slightly every year through 2012.

Future retail electricity rates for the IOUs depend to a certain extent on the regulatory decisions of the FERC, the State Legislature, the Governor, and the CPUC, rather than the spot market prices. Most of the IOU electricity rate components are relatively set for the next ten years. Therefore, major rate fluctuations are unlikely.

Because municipal utilities have long-term contracts for energy, their rates depend more directly on the price of natural gas and to some extent the need to replenish their rate stabilization funds.

Chapter III-3: Developing Demand Responsive Loads

This chapter discusses the characteristics of the demand responsive potential, and suggests a specific mix of load curtailment programs to facilitate ensuring reliability in the year 2002. As Chapter III-1 of this report noted, the wholesale and retail market structures are interdependent. Effective generation price signals cannot take place independent of the retail market. Consumers must choose to consume or not consume based on prices that reflect market conditions. They may make this choice directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability. Further, in assessing the tradeoffs between demand response and peaking generators, the Commission believes that large amounts of DR loads can be acquired that are cheaper than peaking generators. This chapter assesses different types of demand responsiveness options and recommends pursuit of an aggregate capability of 2,500 MW through new and/or revised program designs.

Reducing exposure to excessive market prices is likely to be more cost-effective through time than avoiding markets entirely by relying upon command and control decision-making. Reducing exposure is not the same as eliminating exposure. Reducing exposure to excessive prices admits that an occasional dose of high prices in the right circumstances might be the most cost-effective way to satisfy net electricity demand with generation.

Demand response can come from real-time price (RTP) tariffs or dispatchable load curtailment programs that enable end-users to respond to market prices or to adverse system conditions by reducing loads, respectively. Customers on real-time price tariffs either save money by reducing consumption in high-priced periods or shifting loads from high- to lower-price periods. Customers on load curtailment programs respond to incentives to reduce loads when system conditions trigger load curtailment program operation. Both forms of demand responsiveness reduce loads when market prices and/or system conditions warrant this action.

Much remains to be determined about end-users' willingness to participate in demand responsive programs and tariffs**.** Unfortunately, we learned nothing in the summer of 2001 except that constantly changing program designs create great confusion in end-user minds and greatly increases the difficulty of marketing any programs**.** Our experience base with end-user response to demand responsive programs and rates is simply insufficient to be able to guarantee response**.** However, recent experience shows that at least some customers are perfectly willing to trade off reliability for reduced costs. Making short term commitments to load curtailment programs achieves the overall goal of 2,500 MW of demand responsive capability, and can lead eventually to greater reliance upon RTP tariffs and less reliance upon load curtailment programs**.** The Energy Commission has already proposed specific modifications to two existing, CPUC-authorized load curtailment programs that would enable this 1,000 MW of increased load curtailment program capability to be achieved.

Chapter III-4: Effects of Renewable Generation Initiatives

This chapter discusses renewable energy issues arising from the recent changes in the electricity market conditions. Despite substantial Energy Commission *contingent* funding for new renewable facilities through the Public Goods Charge, the current absence of a market for the output of those facilities is threatening the long-term viability of the renewable industry. The Commission's Renewable Energy Program presently has agreements to provide production payments to 1,300 MW of new renewable capacity, *but only after projects come on-line.* How much of that capacity comes to fruition, however, is dependent on whether project developers can find a buyer for their power.

As a result of the electricity crisis, the market opportunities available to renewable facilities have been dramatically altered. The Power Exchange has disappeared. Utilities are either unable or unwilling to buy. Direct Access has been suspended, so selling to a "Green" Electric Service Provider is no longer an option. The Department of Water Resources contracted for only small amounts of renewable energy, and has ceased making long-term commitments. The newly created Power Authority is not yet in a position to finance or acquire renewable resources.

There are a number of activities underway in various forums that could potentially alleviate the no-market dilemma. The Legislature may enact a Renewable Portfolio Standard, the California Public Utility Commission's current utility procurement proceeding could result in a renewable purchase requirement, a renewable-only form of direct access may be restored, or proposals emanating from the California Consumer Power and Conservation Financing Authority might provide a remedy. But until suitable buyers for renewable energy materialize, there will continue to be a cloud over the future development of new renewable facilities.

The legislation extending the Energy Commission's renewables program stated renewables would add needed generating capacity while promoting diversity and reducing the need to burn fossil fuels. The Energy Commission has established a target of meeting 17 percent of California's energy demand with renewables by 2006. To respond effectively to changing conditions, the Energy

Commission needs to maintain its flexibility in determining the allocation and distribution of funds for its efforts in renewable energy.

Chapter III-6: Siting Issues

In response to the energy crisis, the Energy Commission has taken steps to expedite the licensing of new power plants. This chapter discusses these recent changes to the licensing process, current trends in licensing power plants, the interactions of transmission constraints with power plant licensing, the outcome of the new expedited review process, and remaining constraints to power plant licensing. This chapter finishes with suggestions to help alleviate some of the licensing constraints.

During the electricity emergency, the Energy Commission was successful in bringing new capacity on line by conducting early site screening for the emergency projects, assisting developers in processing project compliance amendments, and overcoming roadblocks to completing construction,

The Energy Commission will support efforts to improve planning for new generation and transmission lines to address congestion, system reliability and efficiency issues. Forecasting the electricity supply and demand balance requires more than a calculation of demand and supply. It also requires the assessment of the locations of demand increases and of new generation resource additions to avoid local transmission system congestion and generation deficiencies. Integrated electricity planning, which considers both transmission and capacity solutions should continue so the most economically efficient and reliable supply/demand balance has a better chance of being achieved.

The Energy Commission will continue to support consolidation of transmission line permitting in California. Although the Energy Commission licenses transmission lines needed to interconnect a power plant under its review to the transmission system, other transmission projects are permitted by multiple agencies. The overlap, inconsistency and inefficiency created by such permitting pose potential constraints to expedited licensing of new generation and transmission projects.

Environmental and permitting issues potentially constrain the Energy Commission's ability to site new capacity additions efficiently without resulting in contested proceedings or potentially significant adverse impacts. These issues include the availability of emission offsets, water supply and water quality impacts, the timing of federal permits, land use conflicts, transmission congestion, and natural gas supply constraints. Working with other agencies, the Energy Commission directs its Policy Committees and Staff to provide guidance or assistance regarding these constraints on licensing new capacity.

Part I Electricity Market Developments – Setting the Stage

Part 1 summarizes the factors that created the volatile electricity market fluctuations of the last several years. It describes the market volatility since 1996, actions taken to stabilize the market in the summer of 2001, the electricity supply outlook for expected near-term trends, and long-term considerations for maintaining a reliable, reasonably priced, and sustainable electricity system.

Market Volatility Since 1998

Assembly Bill 1890, Monopolies to Competition

The California Legislature passed Assembly Bill 1890 (AB 1890 – Statutes of 1996, Chapter 854) to restructure the electricity industry. The State restructuring law dramatically changed the market system that was in place for more than eighty years for serving the electricity needs of California homes, businesses, industry and farms. AB 1890 establishes the Legislature's intent to:

- Ensure that California's transition to a more competitive electricity market structure allows its citizens and businesses to achieve the economic benefits of industry restructuring at the earliest possible date.
- Create a new market structure that provides competitive, low-cost and reliable electric service.
- Provide assurances that electric customers in the new market will have sufficient information and protections.
- Preserve California's commitment to developing diverse, environmentally sensitive electricity resources.

AB 1890 made fundamental changes to the structure of the electricity market to increase reliance on competitive market forces. Municipal utilities were not required under AB1890 to participate in the restructured electricity market and most continue to serve the needs of their customers by generating their own power or with other market transactions initiated at their own discretion.

One of the intended features of electricity industry restructuring in California was that consumers who previously purchased electricity from investor-owned electric utilities could then choose their electricity provider. AB 1890 also created a new market structure featuring two state-chartered, nonprofit market institutions. The Power Exchange (PX) was charged with providing an efficient, competitive auction to meet electricity loads of exchange customers, open on a nondiscriminatory basis to all electricity providers. An Independent System Operator (ISO) was given centralized control of the investor-owned utilities' transmission grid and charged with ensuring the efficient use and reliable operation of the transmission system. These evolving market institutions and merchant facilities presented new and different issues for policy makers.

Market Transformation

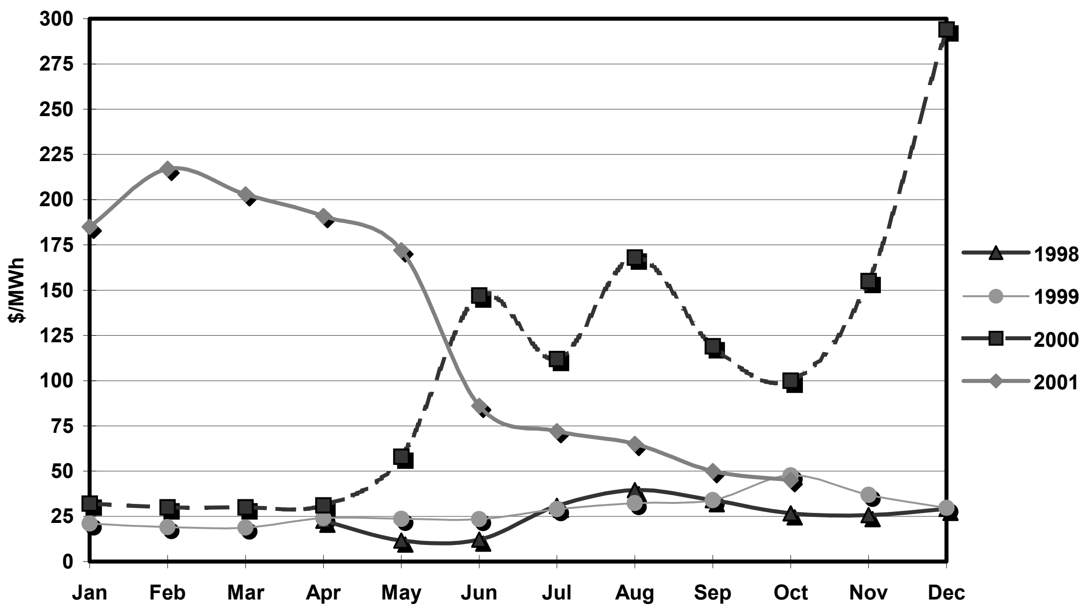
The restructured electricity industry took form in early 1998 and the new market appeared to be off to a good start. Wholesale electricity prices initially tracked expectations averaging $33 per megawatt-hour, which was close to the marginal cost of power production. Unfortunately, many implementation problems developed over time to jeopardize the original goals of establishing a competitive electricity market. Ultimately, these unanticipated problems escalated to "energy crisis" levels in 2000, inducing serious near-term financial and reliability risks throughout the West. Whatever the causes, California's efforts to substitute competition for cost-based regulation in the generation sector of the electricity industry have fallen substantially short of expectations.

Market occurrences in 2000 raised serious questions about the ability of the market structure to provide affordable and reliable electricity supplies for California's residents and businesses. Electricity market problems include the following:

- extremely high electricity costs,
- decreased reliability in the form on ISO Emergencies and rotating outages,
- very high profits by generators and wholesale power sellers,
- large debt incurred by utility distributions companies on behalf of retail customers, and
- large amount of revenue flowing from California consumers to a few sellers.

Wholesale electricity cost the ISO's customers $27.1 billion in 2000, more than triple the amount spent during 1999 ($7.4 billion) and five times 1998 expenditures ($5.5 billion, excluding the first quarter)[1]. The estimates include the costs for Power Exchange energy, bilateral contracts, real time purchases, and ancillary service requirements; these estimates, however, do not include any additional costs that other California municipal utilities incurred over the period. **Figure I-1** shows the average monthly wholesale costs incurred in 1998 through the first half of 2001. Average costs significantly declined in 2001 as the market stabilized.

Figure I-1
Monthly Average CAISO Wholesale Electricity Costs
($ per MWh)



Sources: 1998-1999 Power Exchange Market Clearing Price
2000-2001 ISO Market Analysis Report, Sept 20, 2001

Most retail customers have not seen the high wholesale costs reflected in their monthly bills. Customers of the investor-owned utilities (IOUs) had their rates frozen as part of the overall legislative design for restructuring. During the summer of 2000, the electricity that the utilities purchased in the Power Exchange doubled and then even tripled in price. Because of the rate freeze, the utilities could not pass these expenses to their customers, leaving PG&E and Edison with negative balances in their revenue accounts. PG&E ultimately declared bankruptcy on April 6, 2001. Although Edison is in the same situation as PG&E with a revenue deficit approaching $3.8 billion dollars, the utility has been working with the California Public Utilities Commission to solve its problems without declaring bankruptcy.

The severe and volatile price fluctuations that occurred in 2000 and 2001 affected consumers and other sectors of the state economy. The results of the energy crisis ultimately brought about a public outcry for change. To address the energy crisis, the Legislature implemented a number of changes to restructure the electricity market, but some of these changes compromised some intended goals of AB 1890. For example, customer choice opportunities provided by direct access and the transparent pricing system that the Power Exchange provided have been terminated.

Causes of Market Problems in 2000-2001

During the debate about the cause of California's electricity problems, some have argued that price volatility is an inevitable characteristic of markets run by the ISO and Power Exchange. From this perspective, high prices experienced in electricity markets in 2000 were not a totally unexpected phenomenon. It is true that periods of price spikes and supply shortages are common in commodity markets, particularly in markets like electricity that require significant capital investments. Collapsing prices and excess supplies have historically been common in such markets as well.

Commodity markets use high prices to induce investments in new production capacity. Generally speaking, rising prices from shortages of capacity encourage the construction of new power plants and/or expansion of existing facilities. In most markets, as these additional resources come on-line, prices tend to decline. As a consequence, idle capacity may lead to temporary plant shutdowns, and investors planning to construct new facilities may defer those plans to await higher prices.

However, the electricity market may be inherently different from other commodity markets due to a number of factors. First of all, electricity is a critical service to maintain public health and safety. Furthermore, the generation, transmission and distribution system is complex given the physical reality that coordination of the system is absolutely critical.[2] In addition, the demand for electricity is highly variable due to the weather changes, which can exacerbate the cyclic nature described above. Another distinguishing characteristic of electricity markets is the limited ability to store or stockpile the product. Large inventories help other markets control exposure to wide price swings.

Notwithstanding the nature of commodity markets, many entities have concluded that flaws in market design and rules are a major factor in the excessively high prices for electricity.[3] Some of the major flaws in the market structure and rules that have been identified include the following:

- sole reliance on the Power Exchange spot market to meet demand and balance reliability needs,
- exercise of market power to raise wholesale electricity costs,
- lack of demand responsiveness,
- out-of-market purchases above price caps,
- limited ability of the utilities to use forward contracts,
- conflicts of interest for the ISO Stakeholder Board, and
- unintended consequences of RECLAIM on the electricity market.

Other factors such as weather conditions, tight supplies, increased costs of natural gas and high emission credit prices also contributed to higher costs for electricity this summer. These other factors alone do not adequately explain the levels of prices seen in the ISO and Power Exchange markets from the summer of 2000 through the winter of 2001.

Supply Adequacy Developments

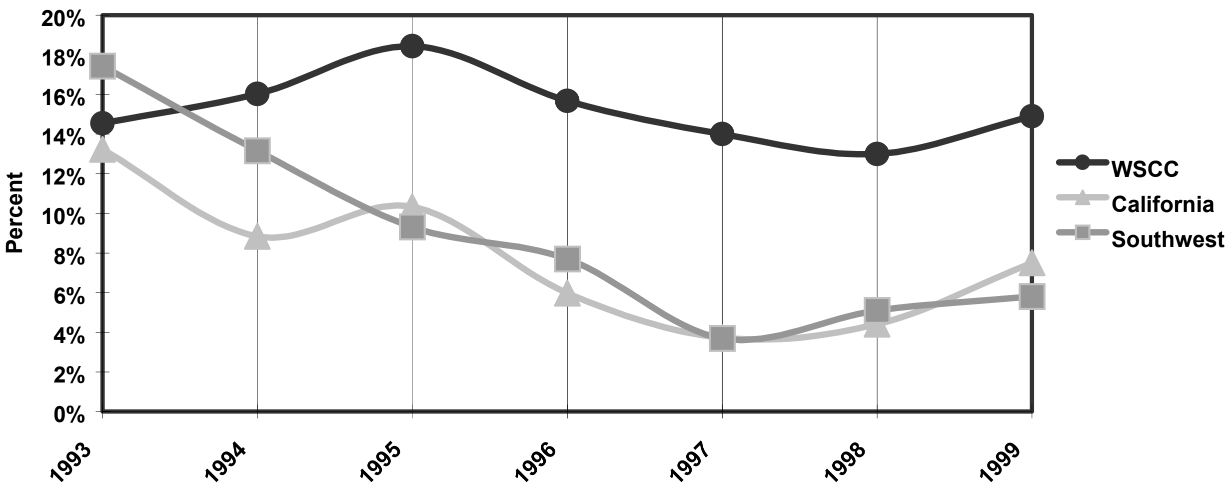
The nation's economy expanded throughout the 1990s. Likewise, so did the electricity consumption in the Western United States. Because power plant development did not keep pace with load growth, reserve margins throughout the Western Systems Coordinating Council (WSCC) and especially in California declined over time. A reserve margin is the percentage of extra generation capacity available at a moment's notice and used by the system operator to adjust for fluctuations in load or other contingencies. Potential problems include a plant going off-line or a transmission line being unexpectedly unavailable.

Figure I-2, shows the peak reserve margins for California, the Southwest and for the WSCC as a whole. The recorded reserves include operational generation, not those facilities that were down for maintenance. While the entire WSCC has maintained double-digit margins, both California and the Southwest had declining reserve throughout the 1990s.

Current reserve margins are not included in **Figure I-2** since the method for calculating the margins that the ISO now reports each day differs from the WSCC estimated peak reserves. The ISO daily reserves are a function of the generation that is contractually scheduled for dispatch and does not measure the actual physical availability of total generation in the system. The ISO scheduled reserve margins dropped below 1.5 percent several times during the 2000/2001-winter period. Part of the reason why reserves dropped to this level was due to financial concerns.

California's rate of load growth was matched by load growth throughout the WSCC. One effect was that a relatively large pool of non-firm capacity, once available on the spot market had begun to dry up. This capacity had enabled California to meet increasing load growth without building new matching capacity.

Figure I-2
Non-Coincident Peak Demand Reserve Margins
1993-1999



Source: Western Systems Coordinating Council, *10-Year Coordinating Plan Summary 1999-2008*, October 1999.

In 1999, the Energy Commission issued a study known as the "Heat Storm" report[4]. Staff predicted that California would face a statewide capacity short fall on the order of 5,000 MW during the summer of 2000 and 2001, based upon a 1-in-10 hot year scenario. Other agencies such as the ISO said that shortages, including rotating outages, were inevitable. A similar capacity shortage was expected on a WSCC region-wide scale. The market appeared to be responding as plant developers throughout the west submitted licensing applications to build new generation facilities. Even though the market did respond to the peak-time-capacity shortage, it was too late to avoid a short-term crunch since power plants take years to bring on line.

The rotating outages that occurred in December 2000 and again in February and March 2001 were attributable to several factors, especially that a larger-than-normal amount of capacity that was not generating. As a rule, generators plan to do maintenance and repairs during the fall and winter because the demand is less and prices are lower. A much higher amount of generation capacity was unavailable during this period. Other factors contributing to outages were generating units being down for retrofits of emission controls. Less power was available for imports to California from other areas of the Western Systems Coordinating Council region as a result of high demand growth and declining reserve margins in these areas. Many Qualifying Facilities were not paid as a result of the IOUs experiencing cash flow problems, and thus these facilities were not producing electricity. **Table I-1** provides a summary of the ISO and statewide outages that occurred over the past several years.

Table I-1
ISO and Statewide Generation Outages

	CAISO		State	
Month	**Outages (MW)**	**Percent of Forecasted Peak**	**Outages (MW)**	**Percent of Forecasted Peak**
1999				
Jan	2,124	7%	3,068	10%
Feb	3,828	13%	5,096	17%
Mar	3,979	14%	5,740	20%
Apr	4,694	17%	5,739	20%
May	2,368	8%	3,032	11%
Jun	967	2%	1,216	3%
Jul	876	2%	963	3%
Aug	834	2%	878	3%
Sep	1,172	3%	1,195	3%
Oct	1,153	4%	1,761	5%
Nov	1,985	7%	2,988	10%
Dec	1,806	6%	2,569	8%
2000				
Jan	1,720	6%	2,423	8%
Feb	2,174	7%	3,243	11%
Mar	2,156	7%	3,389	11%
Apr	2,179	7%	3,329	11%
May	2,963	9%	4,012	13%
Jun	2,011	5%	2,683	7%
Jul	1,915	5%	2,233	6%
Aug	2,179	5%	2,434	6%
Sep	3,409	10%	3,621	10%
Oct	7,206	23%	7,633	25%
Nov	9,754	31%	10,343	33%
Dec	8,039	25%	8,988	28%
2001				
Jan	8,807	29%	9,940	32%
Feb**	9,111	31%	10,895	37%
Mar	10,558	37%	13,737	48%
Apr	12,164	44%	14,911	54%
May	11,787	38%	-	37%
Jun	5,404	17%	6,794	18%
Jul	3,941	12%	5,044	13%
Aug	3,369	9%	4,229	10%

*Includes both forced and planned outages

The electricity outages disrupted activities at businesses, schools, and residences. Traffic was snarled by inoperative traffic signals. Realizing the potential for serious consequences, the ISO made a concerted effort when enacting the outages to minimize the affect on critical services, such as hospitals and emergency support services. These outages came in the fall and winter, during the off-peak period. As such, these outages served to illustrate that a large potential existed for frequent rotating outages during the summer of 2001.

Actions to Mitigate Market Volatility

The consequences of the energy crisis were due to flaws in the market design and electricity system infrastructure limitations. It became clear by December 2000 that stronger government involvement was required to protect the interests of California citizens. To address this need, the Governor developed an energy plan and numerous Legislative bills were passed to stabilize the market. The California Independent System Operator also worked with stakeholders to resolve a number of market design problems. The Federal Energy Regulatory Commission later imposed a number of changes to the market structure to mitigate price and reliability problems. These structural changes, together with the negotiation of new long-term contracts, increased electricity generation facility construction, mandated efficiency programs and reduced energy consumption patterns have moderated the market volatility that was anticipated for 2001.

Governor Gray Davis responded to the market challenge by announcing the primary components of the Energy Stabilization Plan in February 2001. Part of the plan involved issuing a series of executive orders designed to accomplish two objectives: increase near-term supply availability and decrease peak demand. Considering that the Energy Commission identified a 5,000 MW gap between demand and supply, the Governor established two teams, a Generation Team and Conservation Team, to address the problem.

Using a multi-faceted strategy, the Governor's Generation Team put forth a plan designed to use every possible megawatt out of the system. This entailed boosting output from existing plants, restarting other plants that were in short-term retirement, accelerating the review process for plants under consideration and providing incentives to developers to bring plants online sooner than planned.

A number of private and public entities, at all levels of government, cooperated and coordinated the plan. Many lessons were learned along the way. The Generation Team was successful because it attacked the capacity gap problem with the assistance of these entities and a broad set of key players in the electricity market.

The other major effort to bridge the gap was to encourage consumers to reduce electricity demand. The Conservation Team addressed the problem from several different angles. Voluntary conservation was encouraged through public service announcements on radio and television. Californian's were asked to "Flex your Power" by eliminating unnecessary uses of electricity and shifting certain electricity uses, such as doing the laundry, to off-peak times. One of the most successful programs, known as "20/20,"used the promise of a 20 percent rate reduction to those consumers who reduced their electricity demand by 20 percent or more. Californians did "Flex" their power by reducing electricity demand more than 4,828 MW in July 2001.

Other conservation programs were enacted by special legislation such as SB5X, AB29X, and AB970. The legislation employed a variety of methods to reduce consumption, such as time-of-use/real-time meters, rebates for more efficient air-conditioners and appliances, cycling on/off of HVAC systems, replacing traffic signals with more efficient LED type. State Office buildings and public universities were required to reduce HVAC costs by 2 percent. Another significant source of electricity use reductions came from the ISO and CPUC interruptible programs where consumers are given a better rate if they agree to have their power interrupted at times of peak demand. All of these programs, along with the impacts of other voluntary reductions and rate increases, combined to save 7,613 MW.

Federal actions were also taken to mitigate market problems. Electric generation prices paid in the spring and summer of 2001 were as much as 100 times greater than in 1999. Consumer advocacy groups made allegations of unfair market practices and gaming. California was not the only market affected, soaring electricity prices were being paid throughout the WSCC. Prices rose so high that governors of several western states joined Governor Gray Davis in petitioning the FERC to impose WSCC-wide wholesale price caps. After refusing to do so on several occasions, the FERC finally agreed in June 2001 to impose price caps whenever the ISO declares a state of energy emergency (Stage 1 or higher).

Summer of 2001 Developments

Summer 2001 came and went and the power stayed on despite many predictions that the market would continue to be volatile. What happened? Was there ever a real crisis? Or were we saved by the mild weather? Even though the summer of 2001 was a relatively hot summer, as hot as 2000, analysis has shown that Californians pulled together and reduced demand far in excess of what could be expected historically under those weather conditions. It was the culmination of many efforts that "kept the lights on."

Conservation programs and new interruptible power programs created permanent peak load reductions. California consumers heeded the call to reduce demand during peak demand periods.

As implemented, the Governor's Energy Stabilization Plan also had a real measurable effect. A number of new state-of-the-art generation dedicated to California load was brought online this year. Restrictions on how some peaker plants operated were modified. There were 42 projects representing 2,236 MW of new generation that became operational through October of 2001. About 60 percent of these new additions include four large generation facilities that were licensed by the Energy Commission. The other additions include California Independent System Operator peaker projects, several biomass projects coming back online, a peaker facility approved by the Energy Commission, new renewable facilities, and re-rate projects.

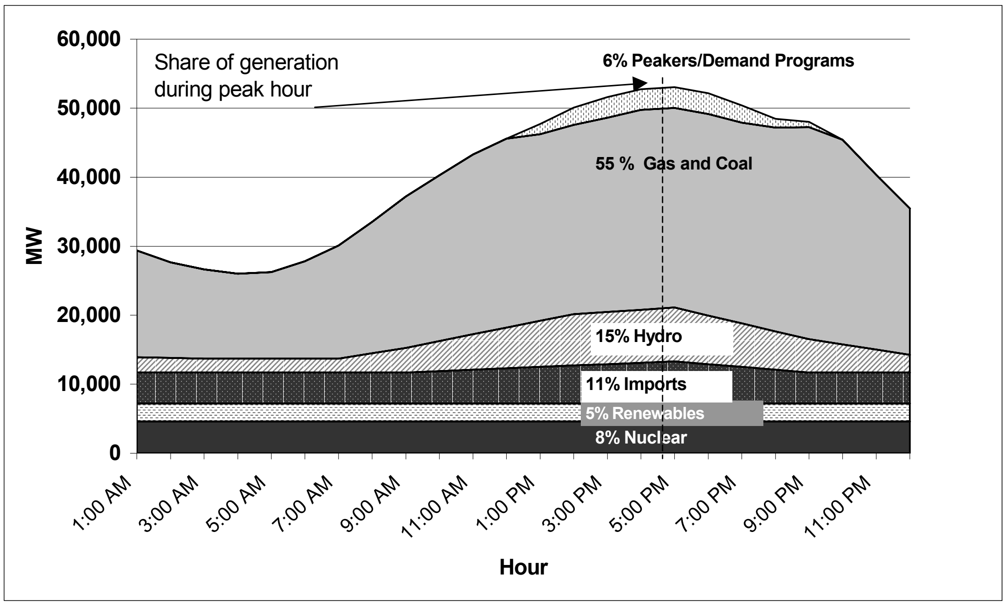
Figure I-3 illustrates the electricity supply and demand profile for a typical hot California summer day. This figure demonstrates the importance of demand responsiveness programs, photovoltaic technology, and load management programs and, if necessary, peaking power plants for providing peak capacity resources for a short amount of time during high demand periods. There is generally sufficient generation capacity available during the shoulder and off-peak periods on a hot day with a one-in-ten probability of occurrence. Demand reduction, photovoltaics technologies and load management programs can also help to reduce the need to produce electricity during the critical peak periods.

Other factors, which did not stem from the Governor's plan, contributed to keeping the lights on during the summer of 2001. Natural gas prices began to fall which lowered generator costs. The Department of Water Resources had firmed-up a large amount of capacity by signing a variety of short-term and long-term contracts, and as a result the price volatility in the spot market declined. Wholesale price caps also factored into decreased price volatility. BPA also agreed to increase generation from its hydro facilities.

Near-term Electricity Supply Outlook

Demand reduction by California's electricity consumers and new generation sources averted predicted outages during the summer 2001 and brought market stability. The electricity supply outlook for the next several years is even more favorable for maintaining reliability and moderating wholesale market price fluctuations. The assessment is based on the assumption that many of the market-related problems that exacerbated the earlier supply problems will be successfully resolved.

Figure I-3
The Electricity Supply and Demand Profile
For a Typical Hot Summer Day



The staff anticipates the addition of 2,703 MW of new generation that have a 75 percent probability of becoming operational by August 1, 2002. This includes renewable projects sponsored by Energy Commission programs. The new generation additions considered for 2002 are already under construction and should be operational to meet the upcoming summer peak demand. There is also a significant amount of new generation capacity that should be operational throughout the West and be available for spot market sales to California.

Predicting the amount of additional new generation development will become more uncertain after 2002. Although there are several thousand megawatts of new power plant capacity currently under review in the Commission's siting process, owners of the plants may decide not to proceed immediately with construction for a number of reasons. For example, the increase in the number of new generation capacity that will become operational in 2002 may depress spot market prices below the level needed by potential new generators to recover their revenue requirement. Because of this possibility, the availability of surplus power beyond firm commitments was not factored into this assessment.

Table I-2 provides a list of probable generation additions over the next several years. Most of these projects are currently under construction or have committed to financial agreements for development. Although there are many more projects under review in the Commission's siting process, only a small fraction of these applications are conservatively considered to be available in the forecast period.

Table I-2
Expected Net new Generation Additions

Year	Status	New Generation
2002	Construction	2,538
	Financing	0
	CEC Review	0
	Renewables	165
	Sub Total	2,703
2003	Construction	2,997
	Financing	77
	CEC Review	391
	Renewables	55
	Sub Total	3,520
2004	Construction	2,687
	Financing	1,070
	CEC Review	360
	Renewables	0
	Sub Total	4,117
2002-2004	**Total MW**	**10,340**

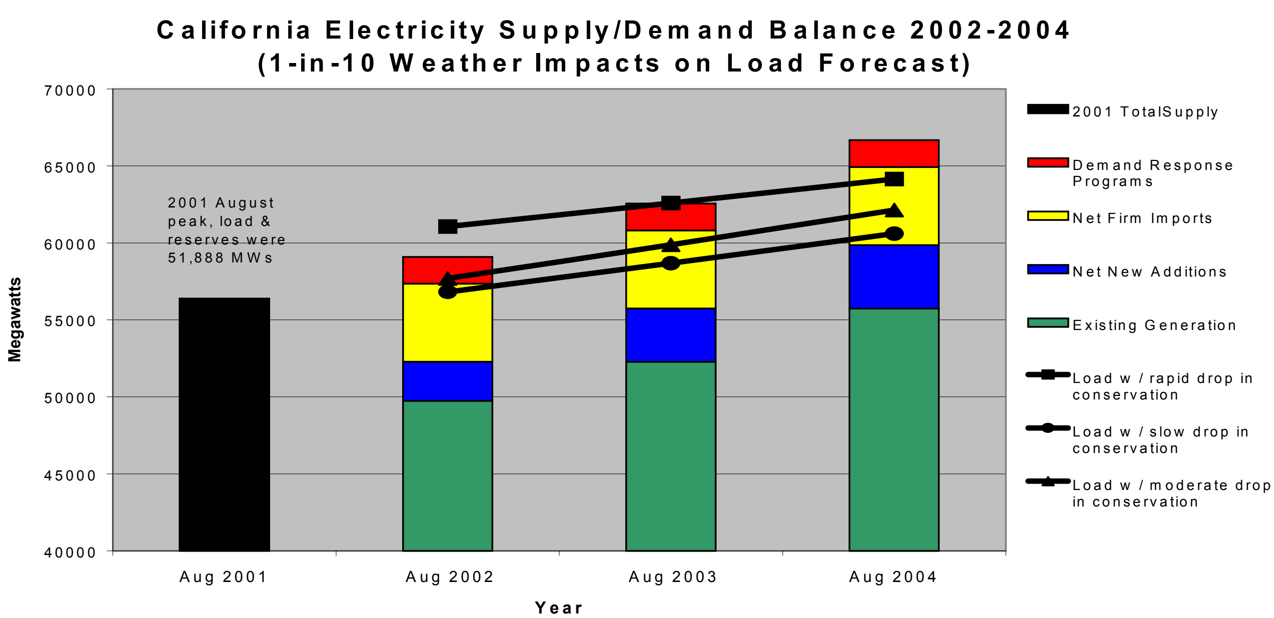
California electricity peak demand levels generally fluctuates with summer temperature variations. Air conditioning contributes to a large portion of the California summer peak demand. Using historical temperature data collected since 1959, the Commission staff classifies temperature conditions according to their probability of occurrence. The summer with hottest average temperatures equals a 1-in-40 year probability. A very hot year has a 1-in-10 year probability and a typical summer season has a 1-in-2 year probability. The Commission staff uses the 1-in-10 year temperature probabilities to estimate future peak demand levels to assess a conservative electricity supply scenario.

The impacts of the energy crisis will be felt by Californians well into the future. It is difficult to determine how many of the actions taken by electricity consumers over the last twelve months will continue into 2002 and beyond. Monthly peak demand in 2001 was significantly lower than would be expected due to voluntary conservation activities and state-sponsored demand responsiveness programs. Determining the amount of this reduction that was a result of permanent technological improvements and how much was due to temporary behavioral changes will continue to be a difficult task into the next few years.

The 2002 summer peak demand is expected to be 54, 248 MW, assuming a 1-in-10 hot summer and a decrease in the voluntary consumer reductions experienced in 2001. The staff also assumes that state-sponsored demand responsiveness programs will successfully reduce 1,744 MW of demand during the summer peak period in 2002[5].

Figure I-4 provides a summary of the "most likely" resource balance scenario assuming a 1-in-10 hot summer peak period. The staff assessment shows that there will likely be sufficient resources available in the next several years to meet statewide electricity peak loads and required operating reserves in the event of a hot summer (1-in-10 probability). The assessment includes the construction of new gas-fired and renewable resources that are expected to be online at the specified periods. The outlook does not address the transmission problem of moving the electricity to the major load centers, therefore local area reliability issues may continue to exist during the forecast period.

Figure I-4
California Electricity Supply and Demand Balance 2002-2004
(1-in-10 Weather Impacts on Load Forecast)



The commission staff has developed several peak demand scenarios to consider varying levels of consumer conservation behavior. The demand scenarios are based on assumptions that there are several decreasing levels in voluntary consumer reductions compared to levels experienced in 2001. The demand levels may vary depending on whether the 2001 consumption reductions were mostly due actual consumer investments in more efficient appliances (i.e. compact florescent lamps or new refrigerators) that will continue to provide savings or simply from household conservation responses to the well publicized energy crisis. The demand scenario with the moderate drop in conservation is considered to have a 75% probability of occurring during the next several years.

The staff finds that there will most likely be sufficient electricity supplies to maintain system reliability requirements through 2004. The following chapters further examine the system reliability risks considering varying levels of development uncertainties.

Long Term Considerations

While the outlook has improved, critical issues need to be resolved to maintain a reliable, reasonably priced, and sustainable electricity system. The market structure that currently exists is an *ad hoc* arrangement, created to respond to the immediate needs of the crisis that was averted. Policy makers now have to choose what kind of market organization and market structure will best serve California.

What should the new market look like? Will it still have a strong competitive flavor or will the State assume a larger role in procuring future power supplies? Does the state need to have a "reserve," and if so, what form should it take and how large should it be? These are questions that need to be addressed, but require thoughtful analysis.

Endnotes

1 Anjali Sheffrin, *ISO Market Analysis Report*, January 16, 2001, Folsom, CA.

2 *Electricity Market Reform in California*, November 22, 2000, John D. Chandley, Scott M. Harvey, and William W. Hogan, provides the following description of the need for system coordination: "Over short horizons of a day or less, generating facilities must work through the transmission network to provide the multiple products of energy, reserves and ancillary services. These same generating facilities must provide all of these products, in the right amounts, and with very limited tolerances."

3 Including the California Public Utilities Commission (CPUC), the Electricity Oversight Board (EOB), the Federal Energy Regulatory Commission (FERC) and the ISO's Market Surveillance Committee (MSC)

4 High Temperature and Electricity Demand: An Assessment of Supply Adequacy in California Trends and Outlook, www.energy.ca.gov/electricity/1999-07-20_heat_rpt.pdf.

5 Staff Report: 2002 Monthly Electricity Forecast, California Supply/Demand Capacity Balance for January to September 2002; Publication Number 700-01-002 www.energy.ca.gov/reports/2001-11-20_700-01-002.pdf.

Part II California Electricity Demand and Supply Balance

This part of the report presents the component analyses comprising the overall electricity supply and demand assessment for the next decade. The first chapter, Chapter II-1, examines the uncertainties associated with forecasting the California electrical system peak demand and energy requirements, given the substantial reduction in consumer demand in response to the recent electricity crisis.

Chapter II-2 examines the uncertainties associated with forecasting energy spot market prices and new power plant completions under a variety of supply and demand scenarios. Even with much of the energy demand served under bilateral contracts, spot market prices remain an important price signal for developers of new supply- or demand-side electricity resources. The goal of this analysis is to estimate spot market prices, which can be used to assess the likelihood of additional capacity expansion and the retirement of existing power plants.

Chapter II-3 examines the potential risks that near-term (2003) capacity resources may be inadequate to meet demand. This chapter explains the probabilistic nature of supply adequacy and attempts to quantify the relative risks associated with key uncertainties that affect supply adequacy.

Chapter II-1 California Electricity Demand

An accurate picture of electricity consumption and demand trends is necessary to determine whether there will be adequate supplies of electricity. According to the North American Reliability Council (NERC) "a credible load forecast is necessary when planning and operating transmission and generation facilities...Even in a market environment, demand forecasts will continue to be crucial for ... those responsible for assessing and maintaining reliability."

Chapter II-1 examines California's electricity demand between 2002 and 2012 according to the following topics:

- Misconceptions about demand growth since restructuring.
- Recent California electricity demand trends.
- The current electricity demand situation.
- Future electricity demand scenarios.
- Patterns of electricity use.
- Recent trends in western states' electricity use.
- Electricity prices and electricity use.
- Energy efficiency resources and the impacts of demand reduction programs.
- The importance of data to demand analysis.

The critical demand forecast issue is uncertainty. Forecasting demand is always uncertain; however, the recent events in California and the nation increase the range of uncertainty in the forecasts presented here. At this point, the Commission cannot predict whether the demand reductions of the summer of 2001 will continue. Nor can it predict the impact from various programs. Other factors add uncertainty to these demand forecasts: the full impact of rate surcharges and newly legislated programs have yet to be seen. Nor is it clear what effect the tragic events of September 11, 2001 will have on economic growth in the state — and on energy growth.

Misconceptions about California Electricity

In addition to uncertainty about the future, there has been some confusion about the past. Numerous assertions about California demand trends and impact of those trends on electricity emergencies and resource scarcity have been made. This chapter starts by looking at several of these misconceptions.

As the summer of 2001 approached, media coverage of the electricity crisis increased along with fears of rotating outages. At the same time several misconceptions about California's electricity demand situation also appeared. The demand situation was characterized as "unprecedented", "resulting from extraordinary growth", and "unexpected". These characterizations were not accurate.

Not Unprecedented Growth

Growth of 3.5 percent in 1999 and 3.7 percent in 2000 was no higher than growth in recent years (1996 and 1997) and growth around a decade ago. During the 70s and 80s the growth rate was three percent per year. In the 90s, growth in electricity use slowed to one percent per year.

Not Extraordinary Growth

As seen in **Figure II-1-2**, growth in peak and energy in the last few years is not greater than growth in earlier years.

For the three years preceding restructuring (1995-1997), overall electricity demand grew by seven percent — the same as the growth in the three years after restructuring. Furthermore, summer peak demand fell by two percent after restructuring, compared to a nine-percent increase before.

Figure II-1-1
California Electricity Consumption not Unprecedented

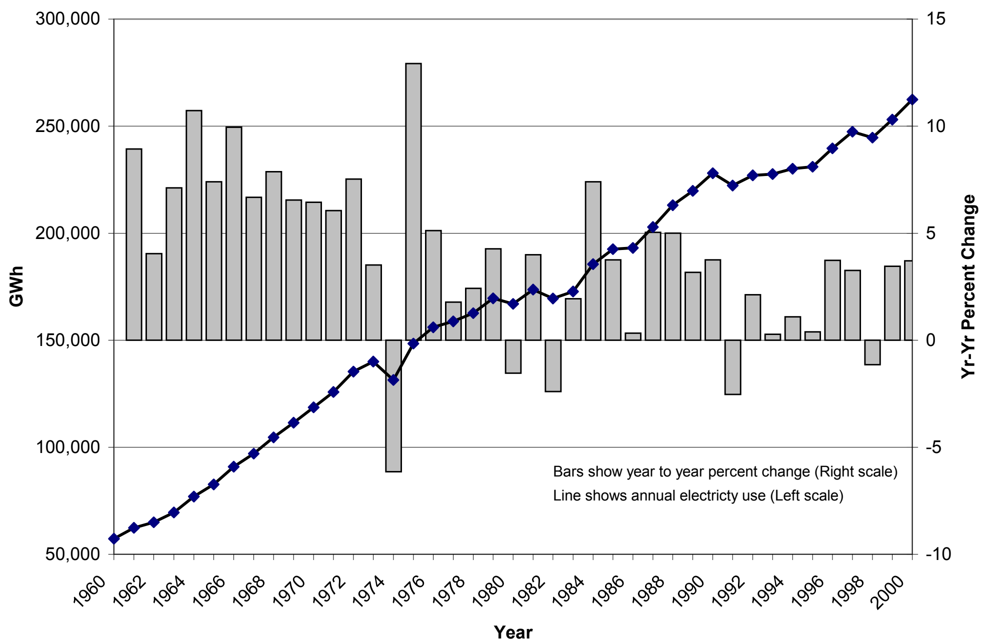


Figure II-1-2
Growth in California Electricity Use not Extraordinary

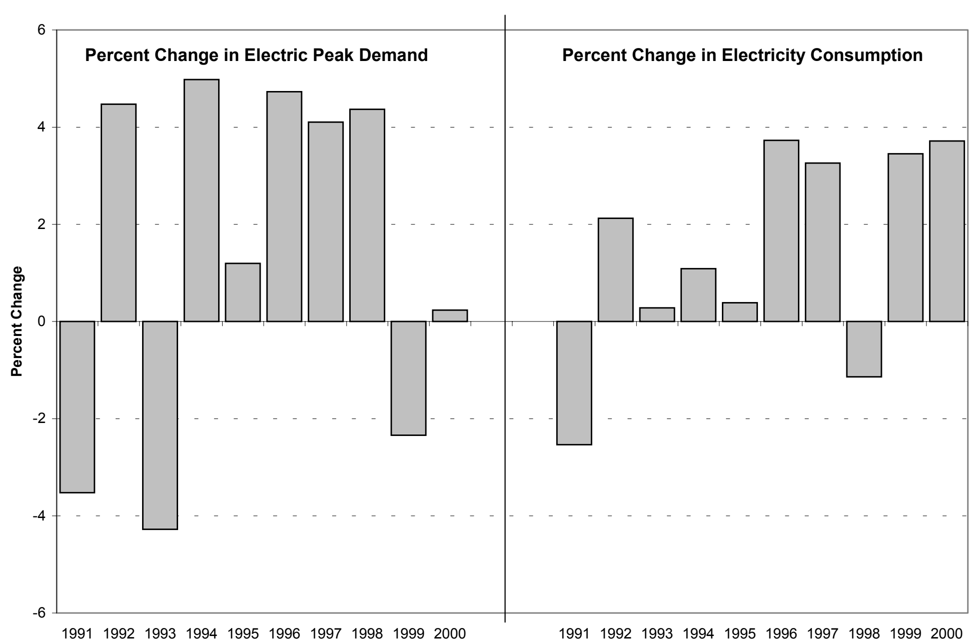


Figure II-1-3 compares actual peak demand to several Energy Commission forecasts of peak demand. If anything, the forecasts are too high; they overestimate actual peaks. This error on the high side did not contribute to lack of sufficient resources.

Recent California Electricity Trends

Recent trends in electricity use are driven by economics and population growth, while average consumption per customer has not changed much.

Increasing economic activity and increasing population are factors contributing to increasing use of electricity. Long term overall electricity use is shown in **Figure II-1-4**. The shaded columns in the figure represent national economic recessions. It is clear that periods of declining electricity use are associated with declines in economic activity. Conversely, economic and electricity growth are related.

Figure II-1-3
California Peak Demand Growth not Unexpected

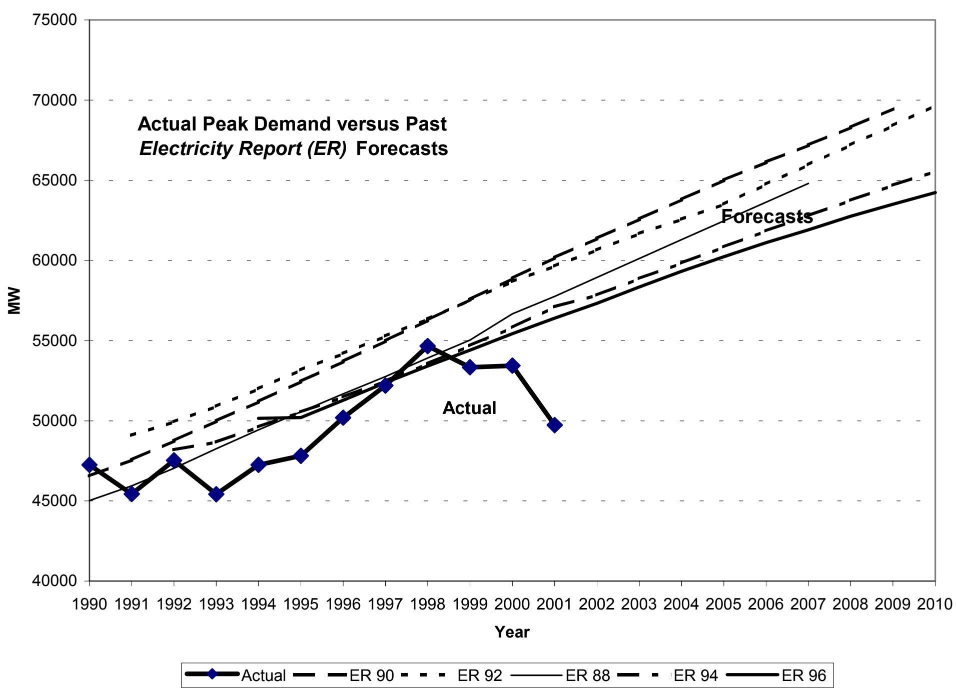
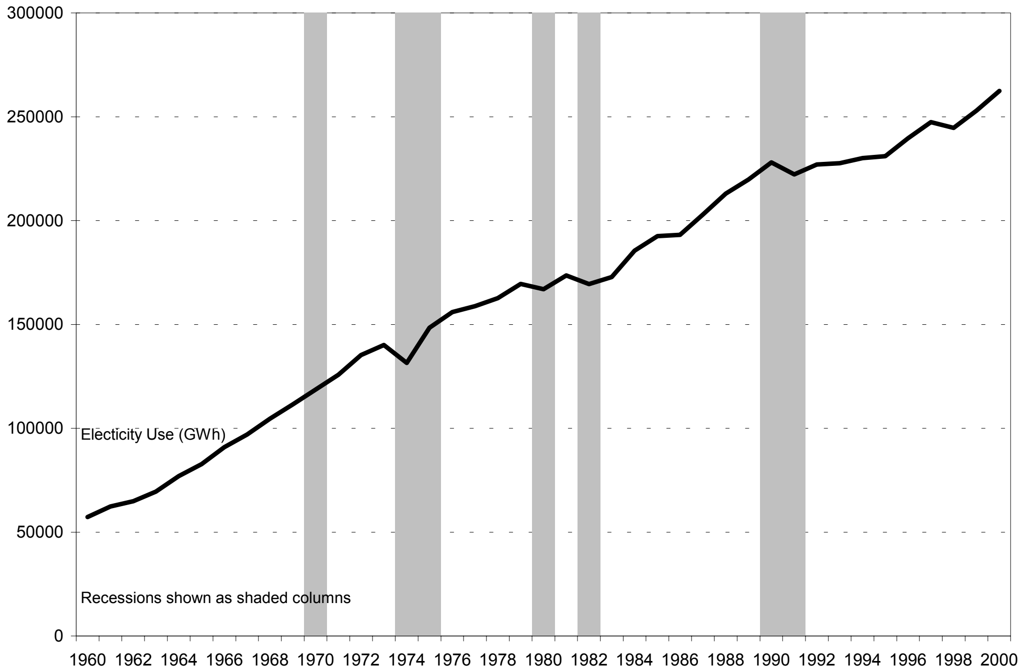


Figure II-1-4
California Electricity Use is Influenced by Economic Conditions



Other factors contributing to growth in electricity use are how much electricity each business and person uses—how efficiently they use electricity—and how that efficiency changes over time. As seen in **Figure II-1-5**, total electricity use per person grew between 1960 and 1974. Use per person grew by 4.3 percent per year in California, by 5.1 percent per year for the nation, and 5.2 percent per year for the western states.

After 1974 use per person patterns changed. As a result of various actions, including Energy Commission building and appliance standards, use per person in California has been relatively flat since 1974, growing only at 0.1 percent per year. In contrast, although growth slowed in the nation and west relative to pre-1974, growth in use per person continued to increase in both the nation (1.7 percent per year) and the west (1.2 percent per year).

Another important factor influencing electricity use, particularly peak demand, is weather. Hot weather causes increased use in air conditioning and increased peak demand.

Figure II-1-5
California Use per Person is Not Increasing

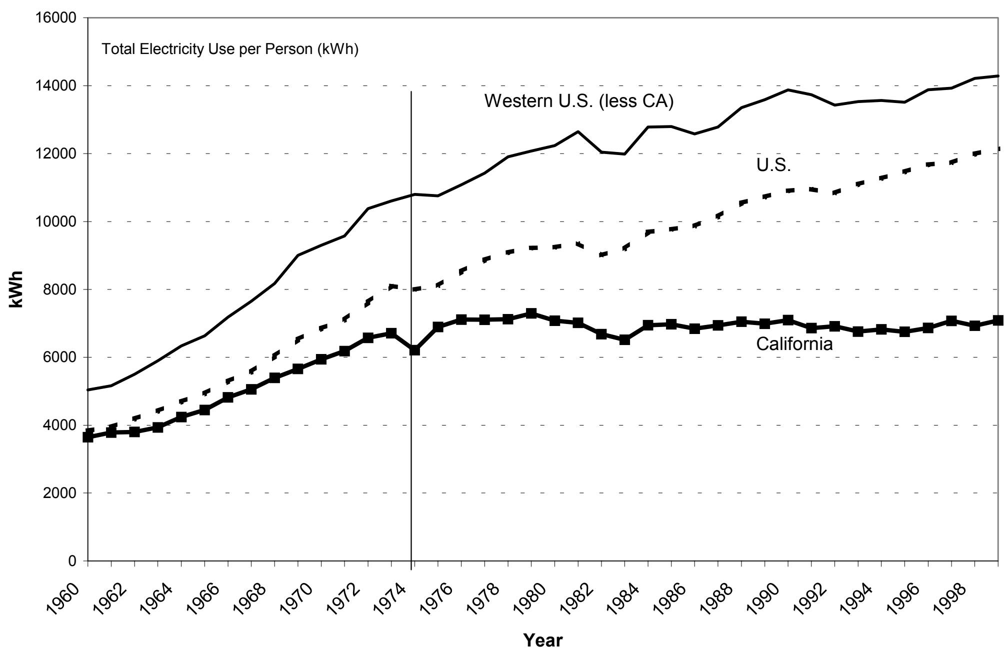
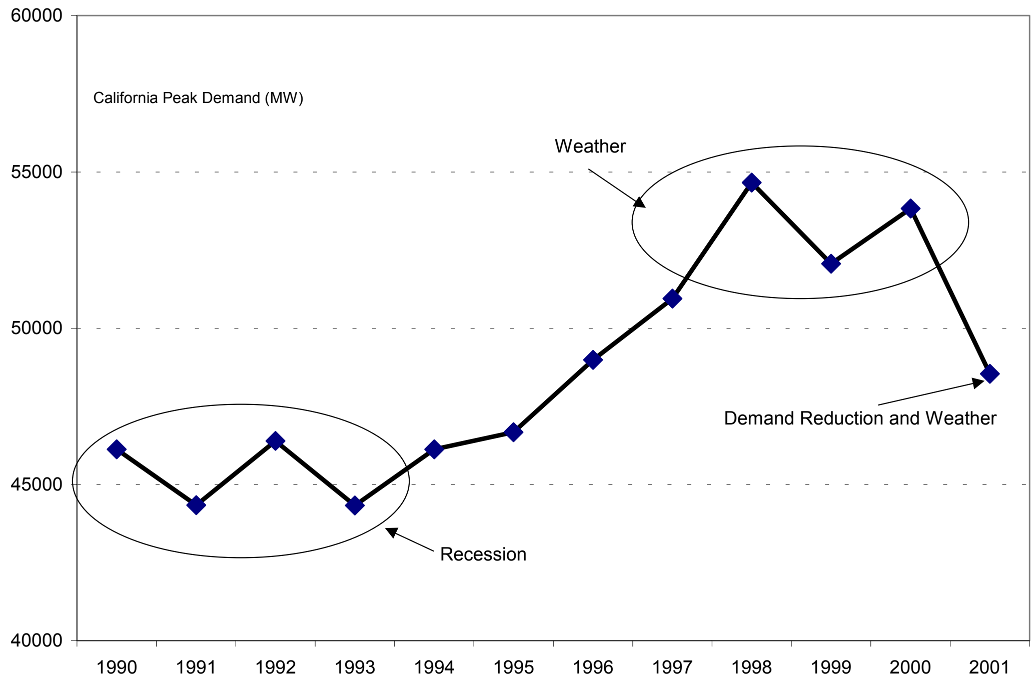


Figure II-1-6 shows the influence of economics and weather on peak demand. The no-growth period of the early 90s was caused by an extended recession in the state. Peak demand growth in the mid-90s reflects the state's economic recovery. In addition, some small weather fluctuations can be seen—1995 was relatively mild, 1996 hot, and 1997 mild.

In the late 1990s weather fluctuations obscure any economic growth trends. August 1998 was the 6th hottest month ever in the state, leading to a very high peak demand. Peak demand in 1999 occurred in July which was much cooler than normal.

The summer of 2000 was hot again, the 25th hottest out of 106 years, leading to an increase in peak demand. The summer of 2001 was as hot as the summer of 2000, the 25th hottest out of 107 years. Looking at heat waves, there were fourteen days in 2001 that the temperature in the Central Valley was 100 degrees or higher compared to only ten days in 2000. In addition, the temperature on the peak day in 2001 was 102 degrees while in 2000 it was 100 degrees. Even though both years have similar temperature patterns, peak demand in 2001 was lower than in the previous three years. This reduction is the result of efforts of citizens of the state to reduce demand and conserve electricity.

Figure II-1-6
Peak Demand Influenced by Economics and Weather



Current Electricity Demand Situation

This section looks at the current electricity demand situation in the state. First, California is compared to other nations and state. Next, there is a discussion of the demand reduction in the summer of 2001.

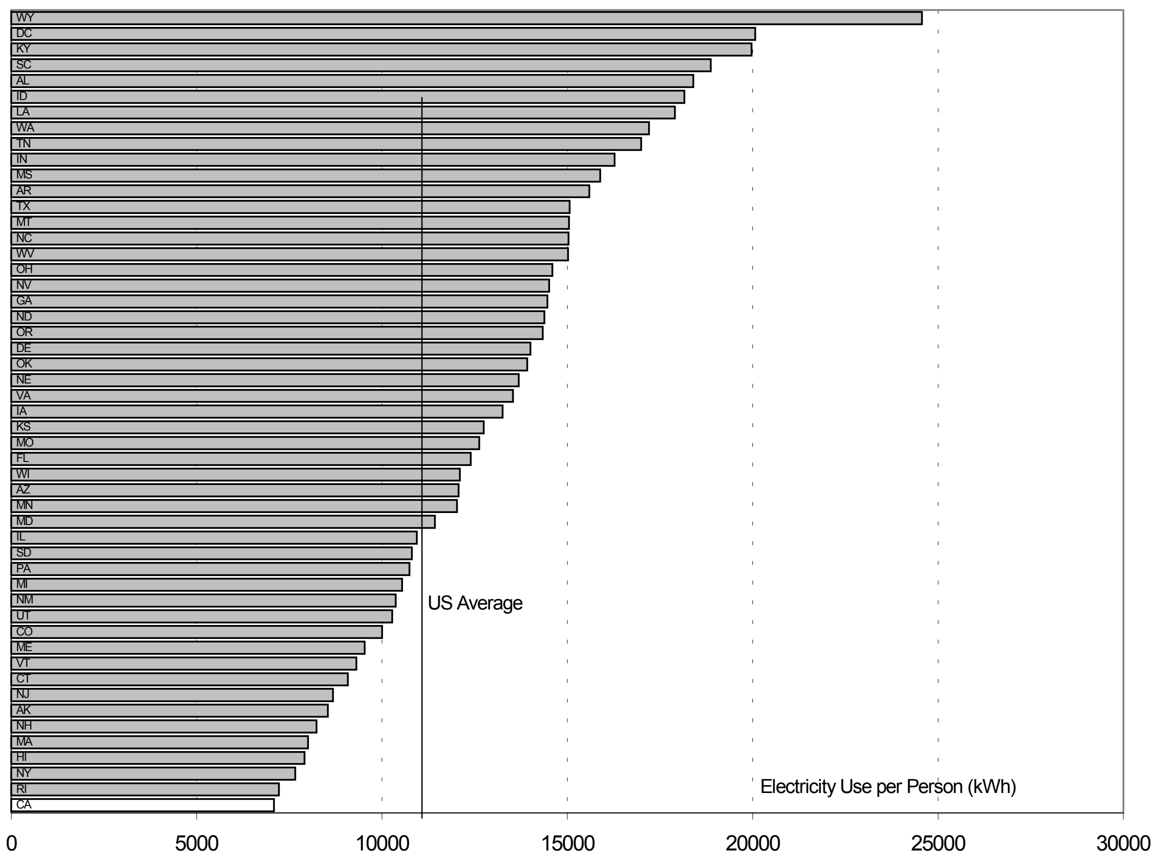
California's Electricity Ranking

If California were a separate country, it would be the fifth largest economy in the world, surpassed only by the United Kingdom, Germany, Japan, and the United States. In addition, it would be the 12th largest consumer of electricity, using slightly more than South Korea and less than Italy.

Among the 50 states, California is the second largest consumer of electricity, surpassed only by Texas. California's 12 percent of the nations' population uses 7 percent of the electricity.

As measured by use per person, California is the most energy efficient state in the nation, ranking 50th lowest out of the 50 states in electricity use per capita (**Figure II-1-7**.)

Figure II-1-7
California is the Most Electricity Efficient State



Summer of 2001

The summer of 2001 was remarkable for what did not happen and for what did happen. What did not happen was frequent system emergencies. Various sources forecast hundreds of hours of rotating outages across the state during the summer of 2001. These outages did not occur. Furthermore, there were far fewer minor emergencies during the summer of 2001. During the summer of 2000, the California Independent System Operator declared 24 stage 1 electricity emergencies and 13 stage 2 emergencies. In contrast, during the summer of 2001, only 2 stage 1 and 2 stage 2 emergencies were declared.

What did happen during the summer of 2001 was an extraordinary reduction in peak demand. Even though the summer of 2000 and 2001 were both the 25th hottest (with high ranks denoting hotter conditions, 2000 was ranked 82nd out of 106 years and 2001 was 83rd out of 107 years), actual peak demand in 2001 was substantially lower than the summer 2000 peak demand. There were 29 days during the summer of 2000 when demand in the California

Independent System Operator's area exceeded 40,000 MW. There were only 6 of these high demand days during the summer of 2001.

The actual peak demand in the summer of 2001 in the Independent System operator area was 41,155 MW. This is about 2,300 MW (or 5.4 percent) lower than the 43,509 MW peak demand in 2000. After adjusting for weather and economic growth, the summer 2001 peak was almost 9 percent lower than the 2000 peak demand.

In addition to summer demand reduction, peak demand was also lower during the winter and spring of 2001. These demand reductions during 2001 are the result of several factors. Unfortunately it is not yet possible to attribute specific levels of demand reduction to specific factors or programs.

The factors contributing to the 2001 demand reduction include:

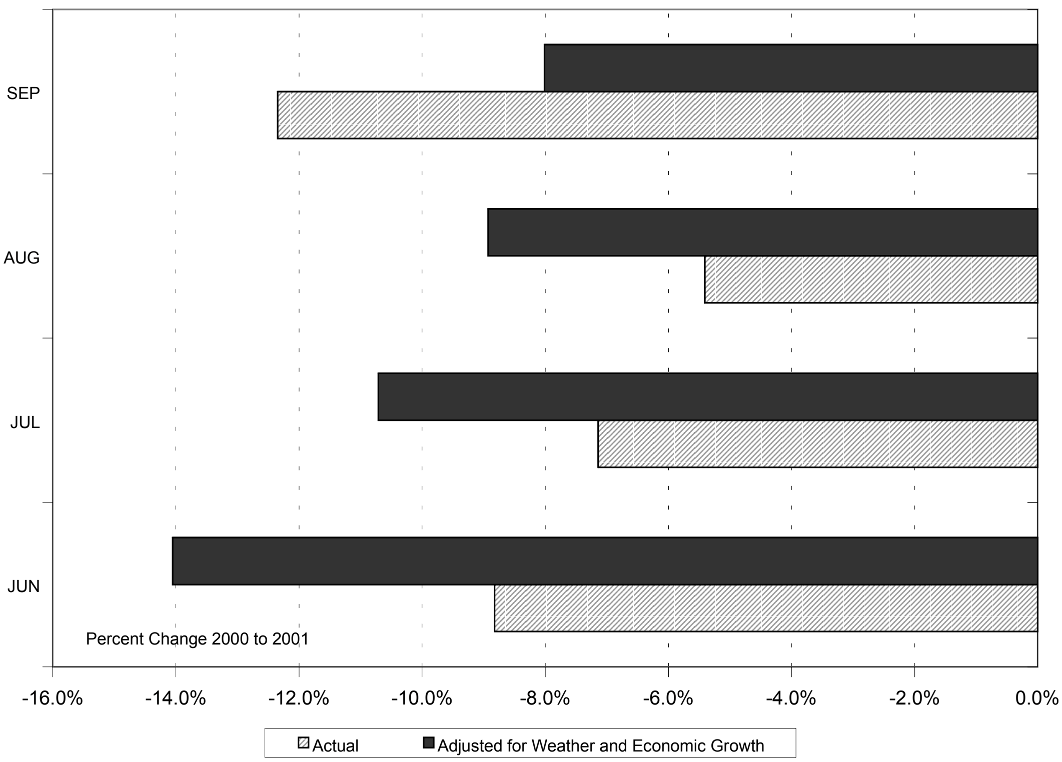
- Demand reduction programs
- Electricity price increases
- The 20/20 program
- Public awareness and voluntary conservation
- Response to crisis, winter rolling outages, and media exposure

Demand reduction programs and customer response to electricity price increases are discussed in more detail later in this chapter.

Over the summer of 2001, there was a reduction of over 3,000 MW in peak demand compared to expected demand levels. This reduction is a result of the factors listed above. In addition to not being able to determine how much of those savings are due to individual factors, it is also not yet possible to determine whether different customers saved different amounts. Data are not yet available to analyze the different savings of residential, commercial, and industrial customers.

It is also not yet possible to determine how much of the demand reduction is due to changes in behavior (e.g., turning up the thermostat to reduce air conditioning use) as opposed to changes in equipment (installing an Energy Star refrigerator). If the reductions are due to changes in behavior, then the savings may disappear in the future if customers return to previous behavior. However, if the reductions are due to equipment changes, these savings should continue into the future.

Figure II-1-8
Summer 2001 Peak Demand Reductions



Electricity Demand Scenarios

The uncertainty about what caused the demand reduction in the summer of 2001, in particular, the uncertainty about how much was due to temporary, behavioral changes and how much was due to permanent, equipment changes contributes to increased uncertainty about future electricity use trends. The three scenarios discussed in this chapter were developed to provide a range of possible electricity futures that account for the demand reductions of the summer of 2001 and uncertainties about future demand reductions and future economic growth. These scenarios combine different levels of temporary and permanent reductions to capture a reasonable range of possible electricity futures.

A two-step process was used to develop the three scenarios shown here. First, the Energy Commission's existing end-use electricity demand forecasting models were used to develop a "raw model output" case. This case was based on forecasts of economic growth. Although these forecasts are reasonably current, they were not prepared in time to capture the slowing growth in California in the early part of 2001 and did not capture any effects of the September 11 tragedy. The case also included the impacts of conservation programs that had been put in place before the summer of 2001. The "raw model output" case did not include the impacts of summer 2001 reductions.

Second, several possible patterns of future trends in summer 2001 demand reductions were developed. These patterns are based on alternative assumptions about the level and persistence of voluntary impacts and permanent, program impacts. These demand reduction patterns were applied to the "raw model output" case to develop three scenarios. One of these scenarios was selected as the most likely case. The other two scenarios represent higher and lower cases. The "raw model output" case from the end-use models is outside of the reasonable range of forecasts bounded by the "high" and "low" scenario and has not been used in any further analysis.

Figure II-1-9 is a chart of the three peak demand scenarios and **Figure II-1-10** shows the scenarios for overall electricity use—the data from the scenarios are shown in **Tables II-1-1** and **II-1-2**.

Figure II-1-9
California Peak Demand Scenarios

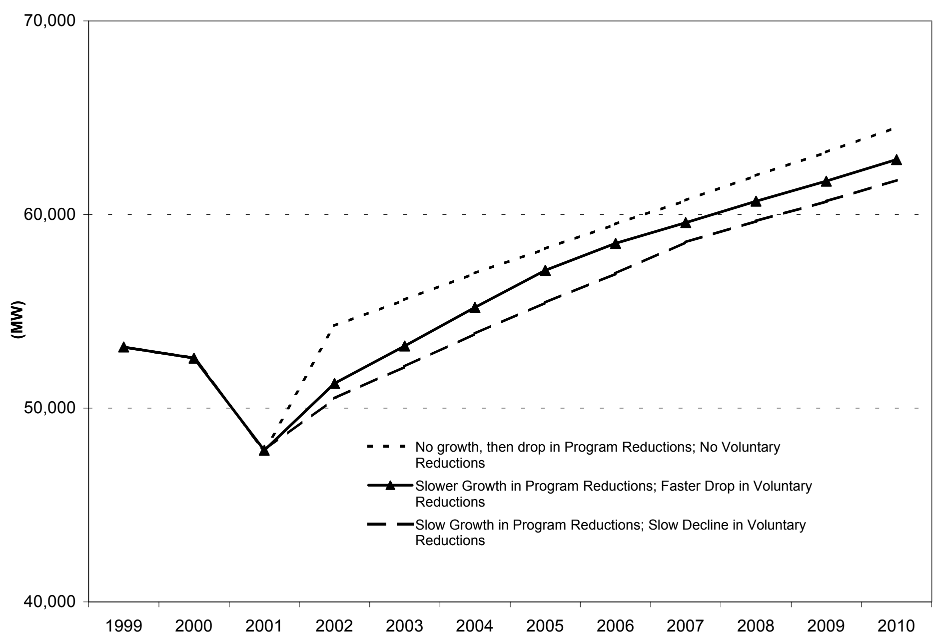


Figure II-1-10
California Electricity Consumption Scenarios

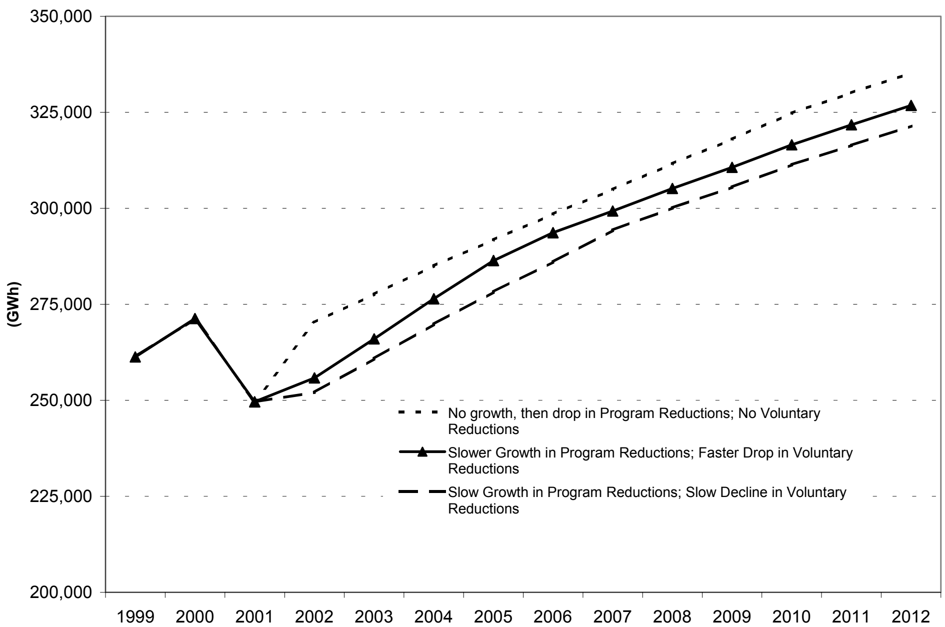


Table II-1-1
California Peak Demand Scenarios
(MW)

Year	Low	Most Likely	High
2002	50,501	51,277	54,255
2003	52,150	53,211	55,600
2004	53,846	55,206	56,973
2005	55,452	57,120	58,232
2006	56,952	58,510	59,502
2007	58,570	59,581	60,735
2008	59,659	60,688	62,011
2009	60,681	61,727	63,223
2010	61,772	62,838	64,512
2011	62,768	63,850	65,552
2012	63,745	64,845	66,573

Table II-1-2
California Electricity Consumption Scenarios
(GWh)

Year	Low	Most Likely	High
2002	252,070	255,829	270,236
2003	260,860	266,011	277,601
2004	269,800	276,414	285,012
2005	278,230	286,359	291,778
2006	286,018	293,625	298,466
2007	294,328	299,263	304,904
2008	300,098	305,132	311,604
2009	305,528	310,655	317,978
2010	311,320	316,546	324,757
2011	316,407	321,718	330,065
2012	321,399	326,796	335,277

The most likely scenario--labeled "Slower Growth in Program Reductions, Faster Drop in Voluntary Reductions"--in **Figures II-1-9** and **II-1-10**, assumes that program impacts increase in 2002 but stay constant after that, while voluntary impacts decrease more rapidly starting with a drop of 1,500 MW in 2002.
The lower scenario--labeled "Slow Growth in Program Reductions, Slow Decline in Voluntary Reductions"--assumes that program impacts grow from 2001 to 2006 while impacts of voluntary reductions drop slowly over the period after a drop of 1,000 MW in 2002.

The higher scenario--labeled "No growth, then drop in Program Reductions, No Voluntary Reductions"--assumes that there are no impacts from voluntary actions in 2002 and after, while impacts of programs stay constant until 2005 and then start declining.

Table II-1-3 shows the demand reduction data used in the three scenarios. In the low scenario, program impacts stay constant at 500 MW from 2002 to 2005. After that program impacts decrease, falling to 0 MW in 2009. The impacts of voluntary programs are assumed to be zero in 2002 and remain so over the forecast period.

In the most likely scenario, program impacts increase to 1,000 MW in 2000 and remain at that level. Voluntary impacts drop from 3,300 MW in 2001 to 1,800 MW in 2002 and continue to fall, reaching 1000 MW in 2006.

Program impacts increase in the high case, growing from 500 MW in 2001 to 2006 MW in 2006. Also, the impacts of voluntary programs drop relatively slowly, falling from 3,800 MW in 2001 to 1,800 MW in 2007.

Table II-1-3
Demand Reductions Used in Scenarios

Year	Scenario								
	Low			Most Likely			High		
	Program	Voluntary	Total	Program	Voluntary	Total	Program	Voluntary	Total
2001	500	3300	3800	500	3300	3800	500	3300	3800
2002	500	0	500	1000	1800	2800	1100	2300	3400
2003	500	0	500	1000	1300	2300	1200	1900	3100
2004	500	0	500	1000	800	1800	1300	1500	2800
2005	500	0	500	1000	300	1300	1400	1100	2500
2006	400	0	400	1000	100	1100	1500	700	2200
2007	300	0	300	1000	100	1100	1500	300	1800
2008	200	0	200	1000	100	1100	1500	300	1800
2009	100	0	100	1000	100	1100	1500	300	1800
2010	0	0	0	1000	100	1100	1500	300	1800
2011	0	0	0	1000	100	1100	1500	300	1800
2012	0	0	0	1000	100	1100	1500	300	1800

Recent Trends in Western States Electricity Use

In addition to information about California trends, it is also important to monitor and analyze trends and forecasts for the western states. Different states have different growth patterns. Uncertainty about future patterns of growth in the west adds to the uncertainty about California electricity supply/demand balances.

Table II-1-4 shows growth from 1989 to 1999 in electricity use, population, and use per person for 11 western states. Growth in electricity use ranges from a low of 0.2 percent per year in Montana to a high of 5.8 percent annually in Nevada.

Table II-1-4
Growth in Western States
1989 to 1999 Average Annual Growth Rate (%)

		Electricity Use	Population	Use per Capita
1	Nevada	5.8	4.8	1.0
2	Utah	3.9	2.2	1.6
3	Arizona	3.5	2.8	0.7
4	Colorado	3.0	2.2	0.8
5	Texas	2.8	1.8	1.0
6	Idaho	2.5	2.3	0.1
7	California	1.4	1.3	0.1
8	Washington	1.3	1.9	-0.6
9	Oregon	1.3	1.7	-0.4
10	Wyoming	0.5	0.5	0.0
11	Montana	0.2	1.0	-0.8

Six states have annual growth in electricity greater than 2 percent. The remaining 5 states have growth in electricity use well below 2 percent per year. The high growth states are characterized by rapid growth in population as well as. Except for Idaho, rapid growth in use per person. On the other hand, the low growth states all have low or declining use per person.

Patterns of Electricity Use

Analyses of electricity resource issues require monthly, daily, or hourly electricity demand data. Hourly data can indicate how long the extreme peak demand period is, influencing how long peaker units will be required to operate or what kind of demand reduction program might best substitute for peaking generation. There are two ways of looking at load data: (1) sorted by day and (2) sorted by maximum value.

Figure II-1-11 shows daily peak demand sorted by day. Relatively stable patterns can be seen in the winter, spring, and fall—in contrast to the load volatility in the summer. While loads are high on weekdays, weekends consistently feature low loads.

Figure II-1-11
Patterns of Daily Peak Demand

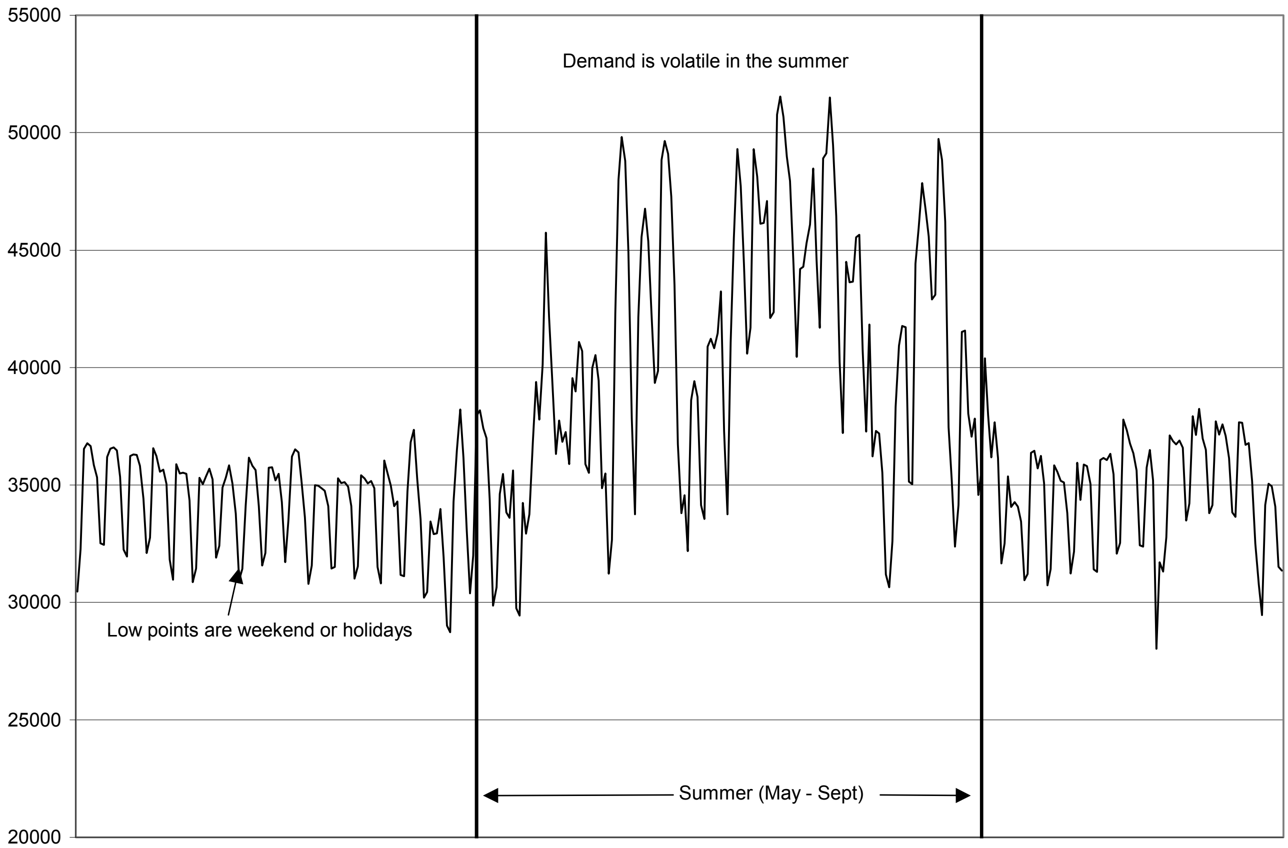
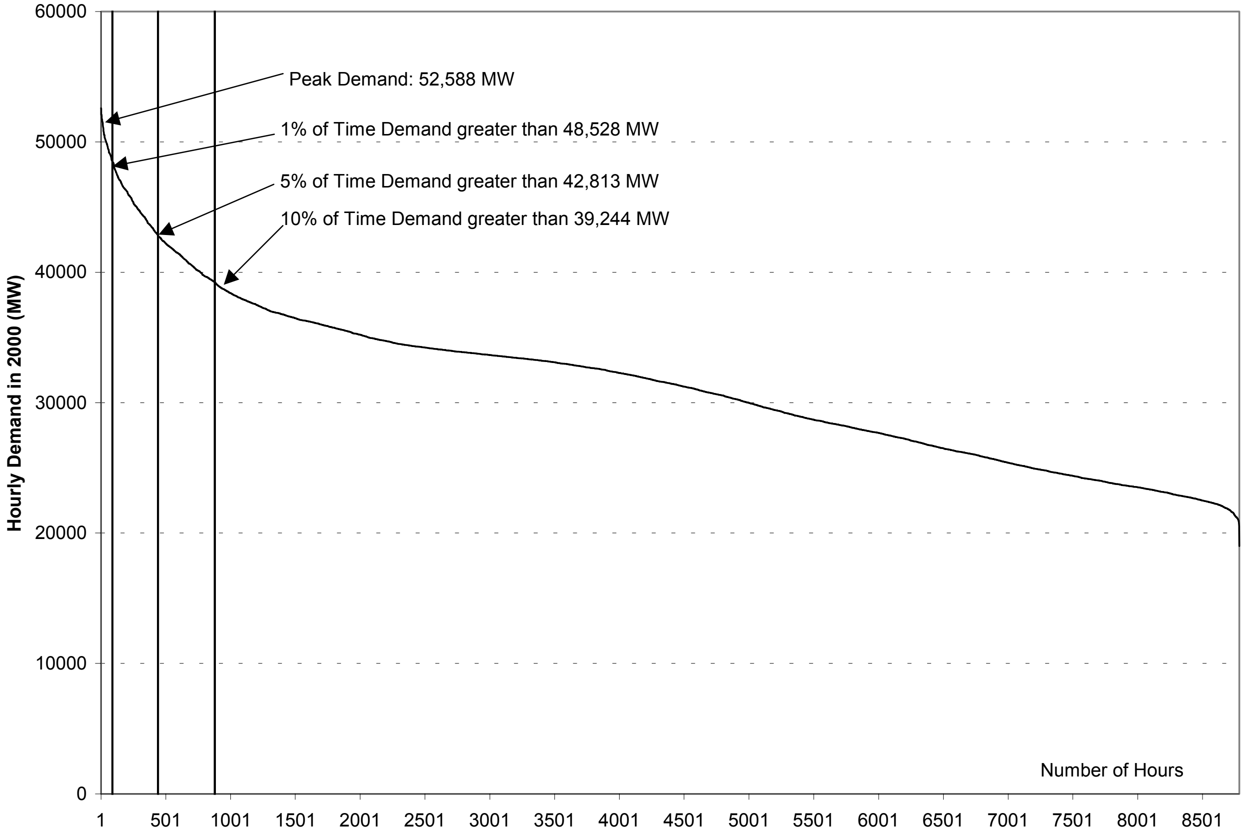


Figure II-1-12 shows hourly demand sorted high to low; this chart is also referred to as a "load duration curve". This figure is useful in determining the number of hours when the loads will be high.

Figure II-1-12
How Many Hours Will Demand Be High



Electricity Prices and Electricity Use

As mentioned earlier, increases in the price of electricity were a factor in the demand reductions seen this year. Until January 2001, electricity prices for PG&E and SCE customers had been frozen. The California Public Utilities Commission approved a 1¢ per kWh rate increase in January 2001 and an even more substantial rate increase in July 2001.

As the price of electricity increases, consumers would be expected to try to reduce their electricity use. The term “price elasticity” is used to measure how much consumers change their use in response to prices. If prices were to increase by 10 percent and electricity use decrease by only 1 percent, this response would be called inelastic, since use did not decrease as much as prices increased. Demand is inelastic if the price elasticity is less than 1.

However, if the response to a 10 percent increase was a 20 percent decrease in use, this would be an elastic response, since use decreased more than price increased. Demand is elastic if the price elasticity is greater than 1.

Table II-1-5 shows ranges of elasticity estimates for electricity prices. These estimates indicate that increases in prices do decrease use since all of the elasticity estimates are greater than zero. Over the short run, electricity use is relatively inelastic—large changes in price produce only small changes in use. As the length of time to respond increases, price elasticity increases. Over the long run, consumers have greater opportunity to adjust their behavior and appliances to changes in prices.

Table II-1-5
Elasticity Estimates

	Short Run	Long Run
Residential	0.06 to 0.49	0.45 to 1.89
Commercial	0.17 to 0.25	1.00 to 1.60
Industrial	0.04 to 0.22	0.51 to 1.82

Energy Efficiency Resources

Energy efficiency programs reduce the energy dependence of California's economy, make businesses more competitive, and allow consumers to save money and live more comfortably. In addition, energy efficiency programs defer the need for new generation or transmission capacity, prevent environmental degradation, and help consumers control their utility bills.

While the fundamental goal of California's efficiency programs and standards continues to be to promote cost-effective energy efficiency and conservation, the strategies emphasized to meet this goal have varied with the regulatory and market environment. Before the restructuring of electricity markets, utilities and state agencies invested in energy efficiency as a cost-effective alternative to generation. With the passage of AB 1890, the focus shifted to achieving longer-term energy savings that would be sustainable after public subsidies ended. The first section of this chapter looks at past savings from energy efficiency programs.

However, with recent electricity market strains, state and utility energy efficiency programs are refocusing on end uses with the largest peak impacts to help prevent shortages and price spikes**.** In addition, legislation has been recently enacted to provide immediate relief in the summers of 2001 and 2002. This new legislation is AB 970, SB 5x, and AB 29x. Although these programs target demand reductions during the summer peak demand period, many programs will also produce year-round savings through improvements to lighting, water pumping, and heating and cooling system efficiency.

Past Energy Savings from Energy Efficiency

Demand-side management (DSM) has included a variety of approaches, including energy efficiency and conservation, building and appliance standards, load management, and fuel substitution. Since 1975, the displaced peak demand from all of these efforts has been roughly the equivalent of eighteen 500-megawatt power plants.

The annual impact of building and appliance standards has increased steadily, from 600 MW in 1980 to 5,400 MW in 2000, as more new buildings and homes are built under increasingly efficient standards.

Savings from energy efficiency programs run by utilities and state agencies have also increased, from 750 in 1980 to 3,300 MW in 2000.

Summer 2001 Peak Load Reduction Programs

Several programs were implemented to quickly bring about energy conservation and peak load reduction to mitigate possible supply-demand imbalances during the summer of 2001 summer. In July 2000, the CPUC directed utilities to implement new peak load programs in the summer of 2001. In August 2000, the California Legislature and Governor approved AB 970, which directed both the Energy Commission and the CPUC to implement cost-effective energy conservation and demand-side management programs.

In April 2001, the California Legislature and the Governor approved SB 5x and AB 29x, which direct the Commission, CPUC, and other state agencies to implemented, as quickly as possible, peak load reduction programs. These two bills create a landmark energy efficiency and demand reduction program that represent the largest conservation effort ever launched by a single state.

Table II-1-6 summarizes the peak reduction programs put in place to help avoid electricity emergencies during the summer of 2001 and beyond.

Table II-1-6
Peak Demand Reduction Programs

Funding Source	Agency	Measure	Funding Source	Total Appropriated ($ million)	Summer 2001Peak Reduction Goal (MW)
SB 5X	CPUC	Residential Incentives and Rebates	SB 5X	$50.0	61
SB 5X	CPUC	Increase CARE program	SB 5X	$100.0	
SB 5X	CPUC	Low-Income Weatherization	SB 5X	$20.0	8
SB 5X	CPUC	Oil and Gas Pumping Efficiency	SB 5X	$12.0	16
SB 5X	CPUC	Incentives for High Efficiency Lighting	SB 5X	$60.0	44
AB 970	Energy Commission	Light Emitting Diode Traffic Signals	AB 970	$10.0	6
AB 970		Innovative Efficiency and Renewables	AB 970	$8.0	32
AB 970		Demand Response Systems	AB 970	$10.0	65
AB 970		Cool Roofs	AB 970	$10.0	25
AB 970		State Buildings and Public Universities	AB 970	$5.5	200
AB 970		Water and Wastewater Treatment	AB 970	$5.0	20
SB 5X		Municipal Utility District Programs	SB 5X	$40.0	35
SB 5X		Demand Responsive Systems	SB 5X	$35.0	120
SB 5X		Cool Roofs	SB 5X	$30.0	15
SB 5X		Innovative Peak Programs	SB 5X	$50.0	90
SB 5X		Agriculture Programs	SB 5X	$70.0	22
SB 5X		Municipal water district generation retrofit	SB 5X	$10.0	25
AB 29X		Time of Use and Real Time Meters	AB 29X	$35.0	500
AB 29X		Local government loans and grants	AB 29X	$50.0	20
AB 29X		Geysers Injection System	AB 29X	$4.5	0
AB 29X		Emerging Renewable Account	AB 29X	$15.0	0
AB 29X		Transfer from Renewable Trust Fund	AB 29X	$15.0	0
SB 5X	Dept. Of Consumer Affairs	Public Awareness Initiatives	SB 5X	$10.0	1,000
SB 5X	Dept of General Services	State Energy Projects	SB 5X	$40.0	30
SB 5X	Dept of Community Services and Development	Low-Income Assistance	SB 5X	$120.0	
AB 29X	Technology, Trade and Commerce Agency	Renewable Loan Guarantee Program	AB 29X	$40.0	10
AB 29X	Ca Conservation Corps	Mobile Efficiency Brigade	AB 29X	$20.0	10
AB 29X	Ca Alt Energy and Adv Transportation Financing Authority	Renewable energy financial assistance	AB 29X	$25.0	

The demand scenarios discussed above include the impacts of pre-2001 programs as well as the programs enacted to reduce demand in the summer of 2001. The scenarios do not include the impacts of possible future programs. In addition, the forecasts do not assume that additional money will be allocated to AB 970, AB 5X, and AB 29X programs in the future resulting in impacts above and beyond those already accounted for.

Importance of Data to Demand Analysis

It is important to better understand what caused the summer 2001 demand reduction. Data are needed to understand which customers reduced demand, including disaggregating data into residential, commercial, industrial, agricultural, and government categories. Within each category, data are needed to see which groups of customers saved the most.

As well as detailed data about customer use, information is needed to determine why customers did what they did. Surveys need to be done to analyze how much of the reduction was due to customer behavioral and permanent response to legislated programs, how much was due to media campaigns, and how other factors.

Although analysis of the summer of 2001 will help reduce uncertainty, uncertainty about future trends in demand reduction trends will continue as the full impact of rate surcharges and newly-legislated programs impact customers. Even if the summer of 2001 were well understood, other factors contribute to uncertainty about future electricity use. The primary factor is uncertainty about economic growth. It is not clear what impact the events of September 11th will have on a California economy that has seen growth slowing since the first of the year.

Chapter II-2 Energy Market Simulations

Introduction

This chapter presents five different scenarios simulating the wholesale spot market for electricity. The scenarios are differentiated by their assumptions about demand growth and new power plant additions during the next four years. The assumptions that characterize each scenario are discussed in detail. The simulation results are presented and discussed, including the spot market prices yielded by the five scenario simulations and the impact of power plant additions on the hours of operation of new combined cycles, peaking units, and the older and larger gas-fired plants. The chapter concludes with a discussion of the implications of the findings for the construction and retirement of capacity during the second half of the decade.

The goal of this analysis is to obtain estimates of spot market prices, which can be used to assess the likelihood of additional capacity expansion (beyond what is already very likely to occur) and the retirement of existing power plants. From April 1998 until January 2001, wholesale spot market prices for electricity largely determined the cost of meeting the energy needs of the customers of California's three investor-owned utilities (IOUs). During the first half of 2001, the California Department of Water Resources signed long-term contracts for wholesale power that will meet a substantial share of the energy needs of IOU customers. These contracts, together with energy from utility-owned nuclear and hydroelectric generation and QF contracts, greatly reduce the share of energy to meet IOU customer demand purchased in spot markets. Accordingly, spot market electricity prices will play a significantly smaller role in determining the wholesale cost of energy for IOU customers.

Spot market prices will continue, however, to have a major influence on the decisions to build new generation capacity and to retire existing facilities. Low spot market prices, those that do not result in profits high enough to warrant investment in new plants, deter capacity expansion. If low enough, spot prices encourage the retirement of plants that cannot cover operating costs. High prices signal the need for new capacity and its profitability. Our results tend to indicate that the addition of new capacity during 2002 - 2005 is apt to drive spot market prices to levels that will render many existing power plants unprofitable and discourage further construction.

Overall Study Design

Staff simulated the inter-connected western wholesale electricity market during the period 2002 – 2012 under different assumptions regarding electricity demand, capacity additions and natural gas prices. Five scenarios were developed, characterized by the rate of demand growth and the amount of new capacity added, and titled according to the resulting reserve margin (Baseline, High, Low, Lower and Lowest). Each of the scenarios was evaluated using "expected" and "high" prices for natural gas. The simulations yield wholesale spot prices for a range of possible reserve margins during the next ten years.

Multisym™, a market simulation model produced by Henwood Energy Services, Inc., was used for this analysis. Given the operating characteristics of each power plant in the Western Systems Coordinating Council, forecasts of electricity demand, fuel prices, available hydroelectric energy and transmission constraints, the model produces estimates of wholesale spot prices across the western U.S. for each hour during the period simulated. It also provides estimates of hourly output and fuel use for each of the plants in the region.

Assumptions Used in Simulations

This section describes the assumptions used in the market simulations and how variations in those assumptions define the five separate scenarios. The assumptions described below include the following:

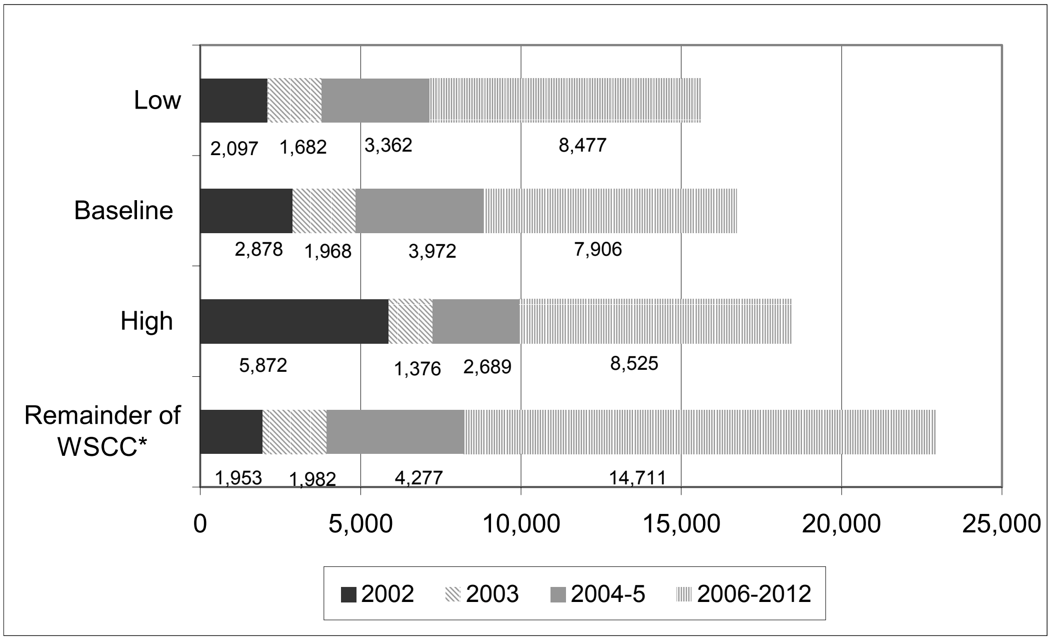
- Demand growth over the 2002-2012 period for California and the other WSCC areas.
- Capacity additions and retirements assumed over the next four years for California and the other WSCC areas.
- Reserve margins that directly result from the demand growth and capacity addition assumptions (these define and scenarios and help explain the results).
- Cost of a new entry into the generation market.
- Hydrological conditions and resulting amounts of hydroelectric generation.
- Long-run natural gas prices.
- Transmission upgrades that are assumed to be constructed during the study period.
- Competitive spot market conditions.

A discussion of the results of the scenario analyses immediately follows the description of assumptions.

Demand Growth

In the market simulation scenarios, the Staff used the three peak demand and energy consumption growth scenarios presented in **Figures II-1-9** and **II-1-10**, respectively. For greater simplicity, these demand scenarios are renamed in this chapter with respect to the trend in demand growth over the decade--Low, Baseline, and High demand growth. As explained in Chapter II, the differences in the increase in demand assumed to occur in 2002 and 2003 reflect uncertainty regarding the persistence of conservation during the next two years; the highest rate of growth used assumes it all but disappears.

Figure II-2-1
Demand Growth Uncertain
Annual Peak Demand Growth (MW)



* The same rate of growth elsewhere in the WSCC was assumed for all scenarios

Capacity Additions and Retirements

The staff has simulated the market under several assumptions regarding the quantity and timing of new additions; the amount of capacity added in each scenario is presented in **Table II-2-1.** All the information available to the Staff regarding new generation capacity planned for construction and operation during 2002 - 2005 indicates that a substantial amount of capacity will be added during the period. A large number of new power plants are being built throughout the western United States; the construction and operation of additional facilities have been approved, but ground has yet to be broken. Beyond these, the number of pending applications for certification and pronouncements by developers indicate that even more capacity is being contemplated. Not all of the new capacity under consideration during this period will be built; there is obviously even greater uncertainty regarding additions during 2006 - 2012.

Table II-2-1
A Boom in Generation Capacity
Cumulative Capacity Additions (MW)

Region	Scenario	Year			
		2002	2003	2005	2012
California ISO	High	5,371	9,753	17,990	23,347
	Baseline			16,362	21,719
	Low			14,270	20,324
	Lower			10,125	16,829
	Lowest			10,125	14,034
WSCC	High	10,909	28,305	51,023	69,333
	Baseline			47,141	65,451
	Low			41,458	61,396
	Lower			35,051	55,638
	Lowest			35,051	46,334

Net capacity additions during 2002 – 2005 were based on information compiled by the Staff regarding facilities under construction, permitted for construction and operation, applications under review, and announced for development. Plants currently under construction were assumed to be completed, as were most permitted plants. A share of the plants with pending applications were included, as were a smaller share of announced plants. The additions prior to August 2003 are the same for each scenario; the capacity assumed to come on line thereafter varies. Events since these scenarios were developed suggest that the 2002 estimate is high for generation additions. However, if regarded as a combination of generation and dispatchable demand reductions, it is reasonable. As reserve margins were increased substantially in every scenario during 2002 - 2005, net additions during 2006 - 2012 were assumed not to keep pace with demand growth.

Retirements were limited to those announced to date and those that were assumed to occur in conjunction with the appearance of new facilities at the same site. The estimates in **Table II-2-1** do not reflect the repowering of 1900 MW of existing capacity in California assumed to occur in 2009. Almost all new generation was assumed to be efficient natural gas-fired combined cycle plants; the major exception being gas-fired peaking facilities added in 2002. A share of the latter – those facilities permitted for temporary operation – were assumed to retire at the end of the summer of 2003.

Resulting Reserve Margins Define the Five Scenarios

The demand growth and resource additions assumed in each scenario yield a corresponding change in reserve margins, for which the scenarios are named. **Table II-2-2** shows the reserve margins for the California ISO control area and the WSCC for each of the scenarios.

Table II-2-2
Reserve Margins Increase

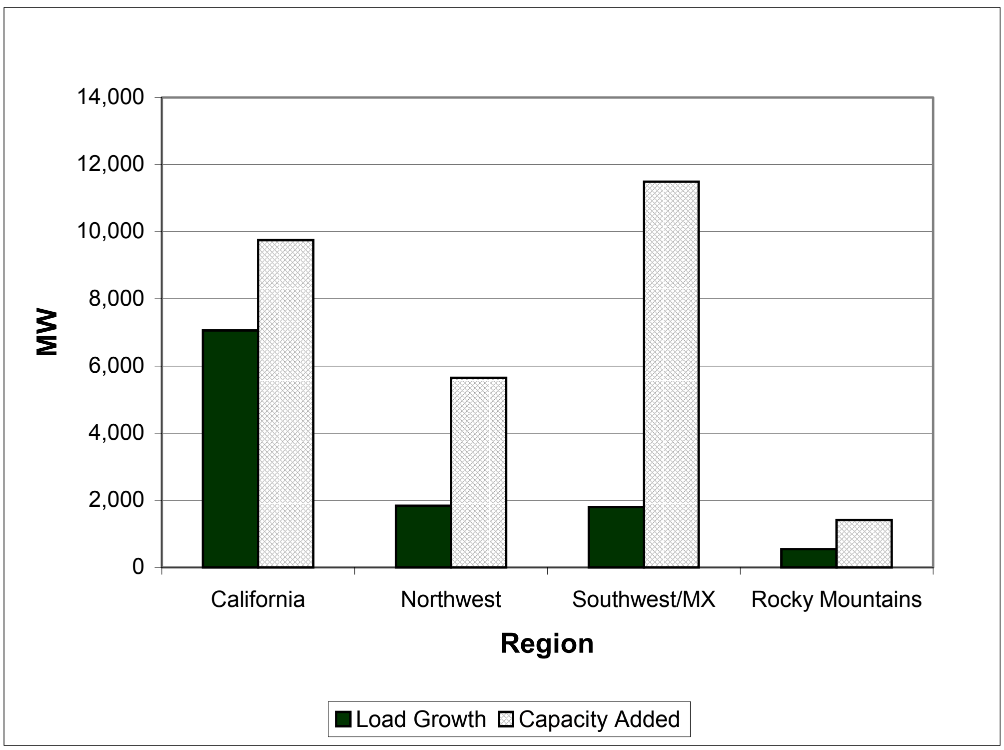
Region	Scenario	Year			
		2002	2003	2005	2012
CAISO	High	20.6%	26.9%	36.4%	27.7%
	Baseline	18.7%	24.3%	29.1%	22.6%
	Low	12.2%	19.0%	22.3%	16.9%
	Lower			13.9%	10.7%
	Lowest				5.8%
WSCC	High	29.5%	38.8%	47.3%	37.8%
	Baseline	28.7%	37.8%	42.9%	34.5%
	Low	25.9%	35.4%	38.0%	30.8%
	Lower			33.6%	27.4%
	Lowest				21.8%

Note: CAISO values include capacity located out-of-state, but owned by investor-owned or public utilities in California

In the High Reserve Margin scenario, demand growth in California is slow in 2002 - 2003; a substantial amount of new capacity is added during 2004 - 2012. In the Low and Lower Reserve Margin scenarios, a large share of the conservation witnessed in California in 2001 is not observed in 2002 and the construction of new capacity is increasingly limited during 2004 - 2012. Finally, in the Lowest Reserve Margin scenario, construction is curtailed even further in 2006 - 2012. In this scenario, the reserve margin in the CAISO control area in 2012 has actually fallen by almost 2,000 MW compared to 2001; this has been offset, however, by an increase in the reserve margin elsewhere in the WSCC of almost 7,000 MW.

Throughout the West, more generation is being added than is necessary to match demand growth. **Figure II-2-2** illustrates additions to capacity reserves from 2001 - 2003 in the WSCC regions under the scenarios with high peak demand assumptions. Capacity additions exceed peak load growth by 2,700 MW in California and a total of 14,400 MW in the Northwest, Southwest and Rocky Mountain regions.

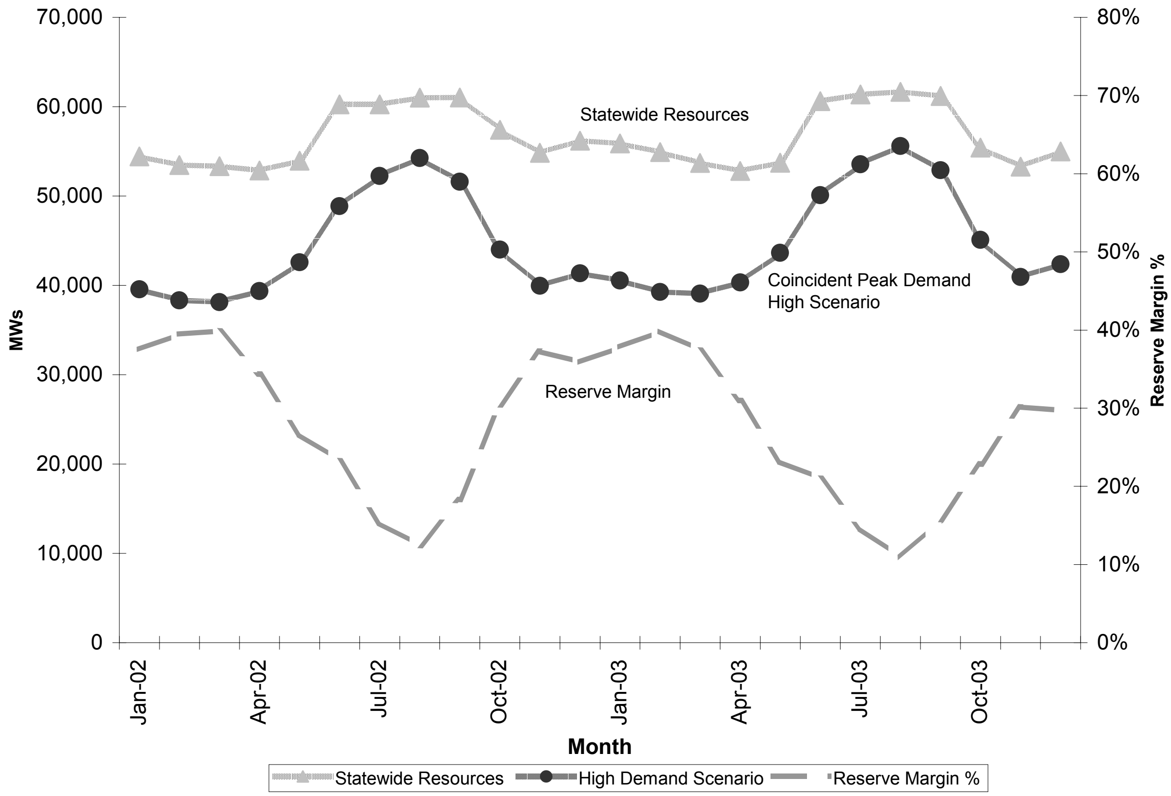
Figure II-2-2
Reserve Capacity Increases
Peak Load Growth and Capacity Additions, 2001-2003,
High Peak Demand Case (MW)



Reliability requires that sufficient in-state generation and imports be available given possible plant and transmission line outages and adverse water conditions, which limit hydro generation in both California and the Northwest. Industry standards have historically set reserve margins so that the inability to meet peak demand be no greater than one day in ten years. This reliability performance target has required planning reserve margins of about 15 – 22 percent, depending on the nature of demand and the mix of capacity resources in a control area. These planning reserve levels have been necessary to guarantee that operators will have 7 percent reserves at all times. On any given day, some installed generating capacity will be unavailable due to operating restrictions, age, a need for maintenance, or water conditions which prevent hydroelectric facilities from operating at full output. Demand may be greater than anticipated; the probability of one-day-in-ten-year temperatures, for example, can drive peak electricity demand above its forecast level. In addition, capacity equal to seven percent of demand must be set aside to ensure system stability in the event of the sudden loss of a power plant or major transmission line.

The simulations suggest that reserve margins will be adequate in the fall through spring in 2002-2003, but will decline to minimum levels in the summer, potentially triggering calls for interruptible load curtailments. **Figure II-2-3** compares expected available capacity to monthly peak demand for California under the low reserve margin scenario. The Staff thinks that this scenario is the most appropriate for capacity planning. A detailed enumeration of the assumptions which underlies the figure appears in **the Appendix, A-1.**

Figure II-2-3
Monthly Load-Resource Balance
High Demand/Low Resources Case



Cost of New Entry

Under deregulation new capacity is constructed in response to market conditions rather than regulatory fiat. In the long run, reserve margins will tend towards levels that yield prices for wholesale electricity sufficient (in conjunction with earnings in ancillary services markets and from "must-run" contracts for local reliability) to adequately compensate investors in new facilities for the risks that they assume. This "revenue requirement" is expressed in $/kW/yr and represents the revenue stream at which investment in new capacity is warranted.

Fixed operating and capital costs for a new combined cycle facility are project-specific. They are also proprietary information of strategic value. Estimates of fixed operating costs range from $7 - $15/kW/yr. Capital costs include construction costs, debt costs, the returns desired by investors and repayment period, debt-equity ratio, tax rate, etc. The Staff estimates that the revenue requirement for most new combined cycle projects is between $85-$100/kW/yr.

As revenue from other sources is apt to be minimal for new power plants, revenues from energy markets must be nearly equal to the revenue requirement. Energy prices must cover much of the variable operating costs, fixed operating costs, and capital costs. The expected annual hours of operation of a new plant, jointly with the revenue requirement, determine the required spread between average wholesale price and variable operating costs. For example, a plant with a revenue requirement of $85/kW/yr, expected to operate 90 percent of the time (8000 hours) requires an average spread of ($85*1000/8000) $10.62/MWh between its operating costs and the wholesale price during the hours that it operates. A plant with a revenue requirement of $100/kW/yr expected to operate 60 percent of the time (5250 hours) requires a spread of ($100*1000/5250) $19.04/MWh.

Hydro Conditions

Staff assumed slightly adverse hydro conditions in the Northwest for the first nine months of 2002; available energy in each month was set at roughly 95 percent of normal. For all other areas and all other periods during the simulation, hydro conditions were assumed to be normal.

Natural Gas Prices

The average annual gas prices in California for 2002 are assumed to be between $3.05 and $3.25/mmbtu; they fall to $2.70 - $2.80 in the summer and rise to $3.50 - $3.60 in the winter. They escalate each year by approximately 2 percent in real terms. **Appendix A-2** includes the annual average real natural gas prices and monthly natural gas price multipliers used in the simulation for each hub in the WSCC, and GDP implicit price deflator series.

Long-run natural gas prices were estimated using the North American Regional Gas Model ™, licensed from Altos Management Partners, Ltd. The model was used to estimate annual average market prices for 2002, 2007 and 2012 for twenty-one hubs in the WSCC. Prices at five additional locations were then derived using estimates of transportation adders. Averages for interim years were interpolated. Location-specific monthly multipliers derived from historical price data were then used to capture seasonal variations in the spot prices.

Transmission Upgrades

The Staff assumed that several major transmission upgrades will take place in California during the simulation horizon. The transfer capability on Path 15 was assumed to increase to 4,400 MW in June,2003, and then to 5400 MW in June, 2005. The transfer capability on the South of SONGS link between the Southern California Edison and San Diego Gas & Electric service areas

(Path 44) was assumed to increase by 450 and 650 MW in January 2003 and 2005, respectively. Finally, upgrades to the southern portions of the West of River and East of River systems were assumed to result in an increase of approximately 800 MW in transfer capability along various paths from Palo Verde to San Diego in January, 2005.

A Competitive Market is Assumed

From summer 2000 until spring 2001, the wholesale electricity market in California was not competitive. During most hours, constraints on supply (due to the need for maintenance, poor hydro conditions, concerns regarding the creditworthiness of the IOUs, and the strategic withholding of capacity), as well as the absence of a price signal that would have reduced consumption, allowed generators to sustain market clearing prices well above their operating costs.

The Staff's simulation of the wholesale electricity market during 2002 - 2012 assumes that it is competitive during all but peak hours, *i.e.*, it is not possible during other hours for the market price to be sustained above the variable costs of the most expensive unit that is operating. Yet it acknowledges that less-efficient generators will only continue operating if they can recover non-variable operating costs such as start-up, no-load and fixed operating costs. Accordingly, these generators, totaling 45 percent of the capacity in the WSCC, were assumed to include these costs in their offers in the spot market during peak hours, with a corresponding effect on the market clearing price. When reserve margins are high, inclusion of these costs will not have a substantial effect on the clearing price, as less-efficient generators operate infrequently. These generators are called upon more often when reserve margins are low; including non-variable costs leads to a larger increase in the average clearing price.

Scenario Results

The remainder of this chapter presents, and then discusses, the results of the market simulation scenarios. Among the quantitative results are the following:

- Average annual and monthly on- and off-peak energy spot market clearing prices.
- Annual capacity factors for new combined cycle, existing large steam boilers, and peaking units.

Spot Market Prices

The annual average wholesale market prices for California are presented in **Table II-2-3** for each scenario.

Table II-2-3

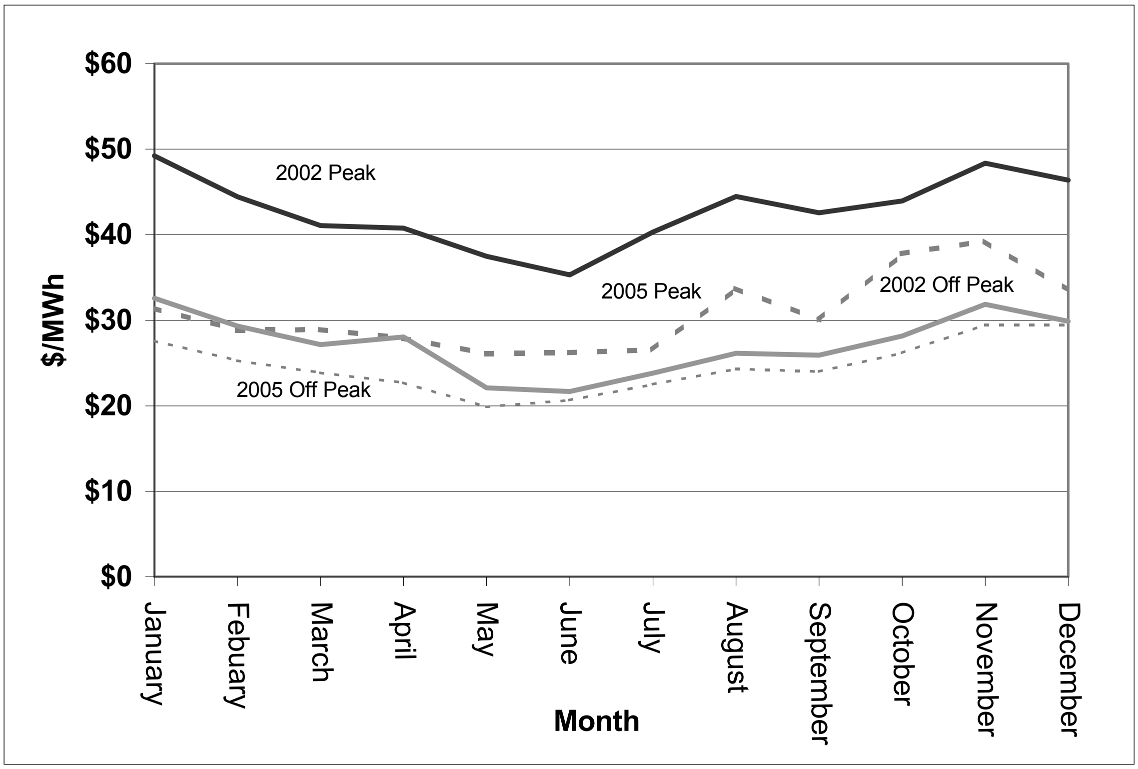
Average Annual Wholesale Spot Prices (Nominal $/ MWh)

Average Price				
Scenario	**2002**	**2005**	**2008**	**2012**
High	$34	$27	$32	$37
Baseline	$35	$28	$32	$38
Low	$36	$29	$34	$40
Lower	$36	$30	$35	$41
Lowest	$36	$30	$36	$44
On Peak Price				
Scenario	**2002**	**2005**	**2008**	**2012**
High	$42	$30	$35	$41
Baseline	$43	$31	$36	$42
Low	$45	$33	$38	$45
Lower	$45	$35	$40	$47
Lowest	$45	$35	$42	$51
Off Peak Price				
Scenario	**2002**	**2005**	**2008**	**2012**
High	$27	$24	$28	$34
Baseline	$27	$25	$29	$34
Low	$28	$25	$29	$35
Lower	$28	$26	$30	$36
Lowest	$28	$26	$31	$37

Peak hours are Monday - Friday, 6 AM - 10 PM

The simulation yields an average wholesale price in 2002 in California of $34 to $37, depending on the extent to which demand returns to trend levels (levels before the summer of 2001). As large amounts of capacity are added during 2003 - 2005, prices fall. New, efficient combined cycles replace higher cost steam turbines; expensive peaking units are needed in fewer hours of the year. As an adequate amount of transmission capacity is available to deliver energy from the Southwest into southern California, and from the Northwest into northern California, capacity additions in neighboring regions serve to lower prices in the state. Prices reach their low point in 2004 - 2005 as reserve margins in both the California ISO control area and the WSCC reach their peaks. As demand growth outpaces capacity addition after 2005, spot prices rise through 2012, their level depending on the extent to which reserve margins decline.

Figure II-2-4
Monthly Average Peak and Off-Peak Spot Prices, 2002 and 2005
Baseline Scenario



Peak hours are Monday-Friday, 6 AM to 10 PM

The Staff also examined daily and seasonal variations in prices for the years 2002 through 2005 as **Figure II-2-4** shows, the simulation yields monthly average wholesale prices that are lowest during May - June and higher during November – December than during the summer months. Low wholesale prices during the spring are not surprising: abundant hydroelectric power due to the spring runoff in the Sierra Nevada, Cascades, and Canadian Rockies, low natural gas prices at the end of the winter heating season, and the limited demand for electricity due to moderate temperatures, combine to keep electricity prices low.

High prices during November – December, relative to summer months, are a result of (a) high system-wide reserve margins resulting from the introduction of new, efficient, gas-fired power plants, (b) increasing maintenance rates for aging facilities and (c) higher prices for natural gas during November – December than during the summer. The wholesale market price for electricity in any hour is set by the operating cost of the most expensive generation unit dispatched to meet demand (the "marginal unit") during that hour. As new, efficient gas-fired capacity comes on line, reserve margins increase, reducing the need for older expensive units. This has the effect of reducing prices most in those periods in which the older expensive units were needed the most: peak hours during the summer. At the same time, maintenance rates for existing facilities have increased substantially during the past two years. As much of this maintenance is performed after prolonged operation during the summer, less-efficient plants are needed more often in November – December than would otherwise be the case. Finally, natural gas prices are higher during November – March than during the rest of the year; in conjunction with the levelizing effect of the first two factors, wholesale electricity prices are thus higher in November – January than during the summer.

New gas-fired capacity also reduces the difference between peak and off-peak prices. During the middle of the night in California – a period of low demand – the unit setting the spot market price is often a relatively low cost coal-fired unit located in the Southwest. During the day, it has historically often been a gas-fired unit with a heat rate of 9,500 – 11,000 Btu/kWh. During peak hours during the summer, the last unit dispatched may have a heat rate of 18,000 – 22,000 Btu/kWh; *i.e.*, this may have doubled the operating costs. When new gas-fired plants with heat rates of 6,800 – 7,200 Btu/kWh are the price-setting units during peak hours, the wholesale price can be expected to fall 20 percent – 30 percent. When they allow a unit with a heat rate of 10,000 BTU/kWh to displace a unit of half that efficiency, a decline in price of 50 percent can be expected.

Capacity Factors

The spot market prices indicated by simulation are well below those needed for new combined cycles to meet their revenue requirements Even if they were to operate 8000 hours a year and ancillary service revenues were to equal 5 percent of energy revenues, the most optimistic scenario yields total revenues in 2005 which contribute $4 – $6 per MWh to the revenue requirement, well below the amount needed in the long-run to warrant investment. The simulation also reveals that new combined cycles are unlikely to operate 8,000 hours per year in 2005.

Table II-2-4 indicates that new combined cycles in California run at an average capacity factor of 78 percent (6,800 hours) in the Lower and Lowest reserve margin scenarios in 2005. They operate at even lower levels elsewhere in the WSCC, indicating that the region has a substantial excess of baseload capacity.

Table II-2-4
Capacity Factors for New Combined Cycles

California				
Scenario	**2002**	**2003**	**2004**	**2005**
High	89%	81%	71%	69%
Baseline	90%	82%	74%	73%
Low	90%	83%	77%	76%
Lower/est			78%	78%
WSCC				
Scenario	**2002**	**2003**	**2004**	**2005**
High	82%	61%	56%	56%
Baseline	82%	62%	58%	59%
Low	84%	64%	59%	60%
Lower/est			60%	61%
Note: Units were assumed to be unavailable 8 percent of the time due to maintenance needs				

The decline in prices from 2003 onward does not portend well for existing less-efficient units. The onslaught of new combined cycles, intended to run around the clock, is likely to reduce prices during many hours well below the level at which existing units can profitably operate. Large units with variable operating costs 25 - 40 percent above those of new facilities, historically used to meet baseload demand, will be reduced to providing limited service, primarily during summer months. **Table II-2-5** shows the decline in the capacity factor of this class of power plants.

A decline in operation of less efficient plants from 3,500-4,000 to 1,000-1,250 hours/year increases the average price they must receive to recover fixed operating costs. In the absence of revenue from other sources, a unit with fixed operating costs of $15/kW/yr must earn $12 - $15/MWh above variable operating costs, as opposed to $3.75 - $4.25/MWh when operating for more hours. Revenue from other sources is apt to be limited, as many of these units are “slow start” and thus unable to participate in ancillary service markets unless they already are producing energy. Revenues from “must run (RMR)” contracts with the ISO are apt to be lower as well, as newer units can provide local reliability services at a lower cost.

Table II-2-5
Capacity Factors for Existing Large Gas Units

California				
Scenario	**2002**	**2003**	**2004**	**2005**
High	27%	12%	10%	9%
Baseline	28%	13%	10%	10%
Low	32%	15%	12%	11%
Lower/est			14%	14%
WSCC				
Scenario	**2002**	**2003**	**2004**	**2005**
High	28%	14%	11%	11%
Baseline	29%	14%	12%	12%
Low	33%	16%	13%	13%
Lower/est			15%	15%

With their hours of operation falling by 50-70 percent, large, relatively inefficient units in California will require higher prices in the remaining hours to make a profit. This might be possible if very inefficient peaking units set the spot market price at high levels for a substantial number of hours. As **Table II-2-6** indicates, peaking units are needed less often as the reserve margin increases during 2003 - 2005.

Existing peaking units in California operate an average of 500 - 600 hours in 2002, falling to 150 - 250 hours in 2004 - 2005. These values are misleading, however, as new, simple-cycle "peaking" units have a wide range of efficiencies. Some of the peakers brought on line in 2001 and scheduled for operation in 2002 are more efficient than many or most of the older large gas units used to date to meet baseload demand. These new "peaking" units will not be used solely to meet peak demand in the summer (100 - 150 hours a year), but also be dispatched during additional hours *in lieu* of larger units. Even in cases where they are slightly less efficient than older, larger plants, they can often compete based on their ability to operate for a handful of hours at a time. Existing large facilities often start slowly and at a substantial cost; they cannot operate profitably for only a few hours. Judging from their requests for permits to operate 3,000 – 4,000 hours or more each year, many of the new smaller facilities being permitted for operation are not "peakers" in the sense that they *expect* to displace older units that now provide baseload service.

Table II-2-6
Capacity Factors for Peaking Units

		California		
Scenario	**2002**	**2003**	**2004**	**2005**
High	5.4%	3.6%	1.3%	1.6%
Baseline	5.9%	3.6%	1.4%	1.7%
Low	7.5%	4.1%	2.2%	2.6%
Lower/est			2.2%	2.6%
		WSCC		
Scenario	**2002**	**2003**	**2004**	**2005**
High	5.1%	2.3%	0.6%	0.8%
Baseline	5.4%	2.3%	0.8%	1.0%
Low	6.5%	2.7%	1.5%	1.4%
Lower/est			1.5%	1.4%

This expectation of high capacity factors for new simple-cycle "peakers" has significant implications for the profitability of older, large gas-fired units with efficiencies in the range of 9,000 – 11,000 Btu/kWh. Not only will they be increasingly displaced by new combined cycles and relatively efficient new smaller units, the latter will, in turn, increasingly displace the least efficient plants in operation - older peaking units – further decreasing the revenue that older baseload plants will earn.

The addition of new combined cycle and simple-cycle units reduces the number of hours that existing peaking units are needed. The capacity factors for older peaking units (those operating before 2001) indicate the intensity of their expected future use. This is illustrated in **Table II-2-7**.

The simulation shows older peaking units operating for only a handful of hours a year. Recovering fixed operating costs will require very high prices during these hours; a unit with fixed costs of $10/kW/yr operating for 50 hours will require an energy price of $200/MWh above its variable costs. In the absence of such prices, older peaking units will not be profitable given revenues from energy markets alone. The absence of very high prices, save perhaps for a few hours a year, will also reduce the profitability of all other power plants.

Table II-2-7
Capacity Factors, Existing Peaking Plants

California				
Scenario	**2002**	**2003**	**2004**	**2005**
High	2.9%	3.0%	0.6%	1.0%
Baseline	3.1%	3.1%	0.5%	1.1%
Low	3.5%	3.1%	0.7%	1.0%
Lower/est			0.7%	1.0%
WSCC				
Scenario	**2002**	**2003**	**2004**	**2005**
High	2.6%	1.2%	0.2%	0.4%
Baseline	2.8%	1.2%	0.2%	0.4%
Low	3.4%	1.3%	0.3%	0.4%
Lower/est			0.3%	0.4%

Spot Market Prices and Changes in the Price of Natural Gas

The Staff analyzed the relationship between the spot market price of natural gas and the wholesale price of electricity by simulating the wholesale market using the same five scenarios, but increasing the natural gas prices across the WSCC as follows:

- 10 percent increases in 2003 - 2004,
- 15 percent increases in 2005 - 2006,
- 20 percent increases in 2007 - 2012.

The results were similar for each scenario; **Table II-2-8** shows that changes in the natural gas price produce roughly similar changes in the wholesale electricity price, with this elasticity increasing after 2002. A close relationship between the spot prices of natural gas and electricity indicates that measures that reduce or stabilize natural gas prices should have a similar effect on prices in the wholesale spot market for electricity.

The spot market prices for natural gas will be the primary drivers of the spot market price for electricity in a competitive WSCC-wide market with surplus capacity. If spot market gas prices are high relative to wholesale electricity prices, generators will resell the gas rather than produce electricity; if gas prices are low relative to electricity prices, generators with available capacity can purchase gas and produce and sell electricity at a lower price.

This relationship reflects several factors, including the increasing reliance on natural gas to meet electricity demand throughout the Western U.S. In 2002, the generating plant that sets the market price – the most expensive unit in operation –during low load hours, *i.e.*, the middle of the night, is often a coal plant. During these hours, the price of natural gas has no effect on the market clearing price of electricity. As loads increase over time, however, natural gas units become necessary in an increasing number of hours to meet a portion of electricity demand; non-gas generation (nuclear, hydro, coal, renewables) alone is insufficient to meet demand in more than a handful of hours a year.

Table II-2-8
Effect of Changes in Natural Gas Price

Year	Change in Gas Price	Change in Electricity Price	Price Elasticity
2002	-	-	-
2003	10%	8.2%	0.82
2004	10%	9.0%	0.90
2005-6	15%	13.3%	0.89
2007-12	20%	17.8%	0.89

Overbuilding and Retirements

The simulation results indicate that capacity additions during 2002 - 2005 are apt to yield spot market prices that will discourage additional construction and create incentives for the retirement of existing facilities. The following factors may encourage building even in the face of low prices in the short term:

- Concerns that resources needed to enter the market may become increasingly scarce encourage the addition of new capacity. These may include desirable locations for power plants, permits to construct and operate, emissions and water use permits, access to transmission lines and gas pipelines, *etc*.

- Demand growth may be over-estimated; the conservation observed in 2001 may be transient.

- The certification and construction of new combined cycles takes two to four years. Developers may be unable to back out of existing commitments when market conditions change. For example, developers may have to commit to purchasing turbines well before delivery, plant construction, and operation.

- Developers may anticipate that competitive forces will lead to the retirement of a significant share of existing capacity during the next three to five years. Should this happen, those building now will be the beneficiaries of the higher prices that result.

The simulation results also indicate that low prices from 2003 onward may be an incentive to retire existing units. However, a substantial amount of capacity will not likely be completely retired and dismantled in the WSCC during 2002 – 2004. Uncertainties related to the amount of new capacity coming on-line, the return of electricity demand to trend levels, and regulation and market structure will contribute to uncertainty regarding spot market electricity prices, and discourage the closure of generation facilities. Owners are apt to incur the costs required to keep less-efficient plants available for operation given the *possibility* of adequate revenues during the next couple of years, if not long-run profitability. Low prices in 2003 and 2004, however, would lead to reduced operation for many plants. This reduction in their competitiveness will encourage their placement into long-term reserve and increased consideration being given to their retirement

Most observers of newly deregulated electricity markets anticipate periods of excess capacity followed by relative shortages and higher prices. The extent of overbuilding in the near-term will depend upon the amount of new capacity that is brought on-line and the number and timing of retirements. Low prices will lead to reductions in reserve margins and an increase in spot market prices; this increase will eventually induce another period of investment. Our analysis suggests that this cyclical phenomenon is an inherent part of the current market structure. Market design modifications are needed to moderate the effects of cyclical investment on the volatility of spot market price of electricity and the reliability of the electrical system .

Chapter II-3 Putting the Risk of Capacity Shortages in Perspective

Overview

This chapter presents an additional probability-based assessment of the risk of Summer 2003 capacity shortages inherent to the supply adequacy analyses presented previously in this report. The 2002-2004 supply adequacy outlook in Part I deterministically accounted for some sources of risk by using a load forecast that had less than one chance in ten of being exceeded and a new plant construction forecast that had less than one chance in four of not being achieved. In addition, it presented three demand scenarios to capture uncertainties about the persistence of recently experienced demand reductions. The system simulation studies in Chapter II-2 are primarily focused on average energy price impacts, so they do not attempt to quantify the risks and magnitude of capacity shortages.

The specific goal of this chapter is to understand how robust is the more deterministic supply adequacy assessment for 2003, found in Part I, by applying more probabilistic risk assessment techniques.[1] In doing so, we illustrate the risk issues that are central to the questions: What risk of supply shortages are we facing in the near term? Do we have "enough" capacity? How much additional risk will the next increment of capacity avoid? What are our options for managing the risk, and how do their risk management performances compare? In addition, the risk assessment in this chapter examines the differences in supply adequacy risks among the various transmission-constrained areas of the state, which was not a feature of the previous supply assessments.

This chapter illustrates how uncertainties associated with specific key risks that affect supply adequacy contribute to the overall risk of shortages. We assessed one demand-side risk to supply adequacy: the effect of temperature variations on peak demand. We assessed three supply-side risks: the effect of hydrological conditions on the availability of hydroelectric generation capacity, the effect of potential construction delays on the availability of new power plant capacity, and the effect of aging on the rates at which generation and transmission facilities are forced out of service. We selected the summer of 2003 as the time period to illustrate the risk assessment because the supply balance was tightest that year and sufficient time remains to take additional action, should that be warranted.

Generally we have found that our probabilistic risk assessment gives us a measure of confidence in the near-term supply adequacy outlook in Part I. Although this work does identify the *possibility* of shortages in excess of those identified in Part I, the probability of their occurrence is very small. Depending on the cost to society of such shortages, actions in addition to those anticipated in the Part I near-term supply analysis might be taken (and their associated expense incurred) to avoid the additional risk of shortages. A cost-benefit analysis of available "supply adequacy insurance" options has not been attempted in this report. However, we do make the case that, if supply adequacy insurance is sought, then the full range of demand- and supply-side options for mitigating that risk should be considered.

Explaining Our Method

Currently, the CAISO requires that operational reserve capacity be maintained and available in an amount equal to seven percent of the peak demand. The level of risk of service outages associated with a seven-percent capacity reserve has been the level of risk deemed acceptable (under regulatory and market conditions that existed before restructuring). Industry standards have deemed to be not acceptable a higher risk of outages associated with a reserve capacity level below seven percent. Likewise, industry standards imply it may be unnecessarily expensive to try to lower the risk of outages by increasing the level of operating reserves to a much higher level above seven percent.

What specifically do we mean by "supply adequacy" in this chapter? The concept of supply adequacy can be expressed by a simple formula:

$$\text{Capacity Resources} + \text{Transfer Capabilities} \geq \text{Peak Demand} + \text{Reserve Capacity}.$$

Since electricity can not be stored in a substantial amount, this relationship must hold at any time, but it is crucial that it would hold at the time of peak load that occurs in California during the summer. If supply is adequate at summer peak, *i.e.*, there are enough power resources and enough transmission grid capacity to deliver power to consumers as needed, then there are good chances that the supply is adequate at other time with lower loads.

However simple the above formula may seem, applying it is not an easy task. First, it is technically difficult to evaluate the many components. For example, evaluating the transfer capabilities of the transmission grid across the entire Western United States requires a very complex non-linear model to account for all power flows. Second, each component contains a range of possible values. This problem can be addressed by examining scenarios, as was done in the previous chapter, or by using a probabilistic approach, which we have done in this chapter.

We have introduced probability into the assessment by using a Monte Carlo approach. We made 300 random draws of values within a described range for key variables. For example, for 2003, 50,000 to 62,000 MW is the range of variation imposed on a baseline peak demand forecast that assumes typical temperature conditions by more extreme -- but very much less likely -- temperature conditions. The temperature condition in each forecast is selected randomly, but is influenced by the probabilities of occurrence of temperatures in the meteorological record. Likewise, random draws were made for the magnitude of in-state and imported capacity resources. The range of variation for in-state and imported capacity resources is imposed by the range of uncertainty associated with forced outages of the generation and transmission facilities, hydrologic conditions that affect hydroelectric generation supplies, and construction delays in bringing new power plant capacity on-line.

A Closer Look at Peak Demand Uncertainty

The effects of temperature on peak demand are well understood by demand forecasters. The potential range of variation and frequency of occurrence of temperatures is well understood by meteorologists. Even though next summer's temperatures cannot be predicted with complete assurance, we do know the probability of occurrence of summer temperatures. Therefore, we can make a quantitative prediction of the risk of temperature's effect on peak demand. Given all of the other assumptions used in this baseline peak demand forecast for 2003, the temperature-related risk of having a peak demand as high as 62,000 megawatts is one chance in forty. We have assumed the temperature distribution is symmetrical, as the low temperature data is not available. Given that, the risk of having a peak demand as low as 50,000 megawatts is about the same. And we can calculate the chance of experiencing any other value of peak demand in between the extremes of the range of variation.

A Closer Look at Supply Uncertainty

In-state generating resources in 2003 can vary between about 43,000 and 52,000 megawatts and imported generating capacity can vary between 5,000 and 15,000 megawatts. This variation in the availability of generation resources is the product of chance effects on generator and transmission line outages, hydrologic conditions, and construction delays for power plants throughout the WSCC area.

The analysis accounts for the chance of forced outages of more than 1,500 generating units located within the Western pool. Each power unit is characterized by its forced outage rate, the percent of time it will be unavailable when called upon to operate. Forced outage rates, the standard unit performance measures used by the electric industry, are based on unit-specific performance history and thus vary unit by unit.

The analysis also accounts for forced outages of about 210 transmission lines throughout the Western pool. These are aggregated into about 100 different transmission links. Each line is assigned a value of forced outage rate according to its voltage. If a line is lost, the capacity of the transmission link comprising the line is de-rated.

The effect of hydrologic conditions on the availability of Pacific Northwest hydroelectric generating capacity is based on the historical water years published in Pacific Northwest Loads and Resources Study by the Bonneville Power Administration. The probabilistic investigation includes the chance of PG&E hydroelectric generation capacity being reduced due to hydrological conditions, but not the chance of SCE or LADWP hydroelectric capacity derates (data were not available).

Lastly, we assigned probabilities of construction delays for new power plants. Potential new resource additions were assigned probabilities that they will come on line as scheduled based on their construction status.

Each of the above-listed factors introduces uncertainty into the forecast of supply adequacy. Their combined effects magnify the uncertainty judgments about adequacy of power supply in California.

Combining Probabilistic and Scenario Approaches

As we have discussed, some of the factors that are considered in this study are probabilistic by their nature, e.g. temperature, hydro conditions and forced outage rates. For these factors probabilistic values based on statistical information are assigned. Other factors could be assigned probabilistic values based on subjective judgements. For example, subjective probabilities to assess resource additions were based on Commission Staff's general knowledge gained in the process of issuing permits for new construction. Finally, factors like economic activity cannot be reasonably evaluated in probabilistic terms.

To address all the variety of uncertain factors, we exercised a mixed approach that combines scenario analysis with probabilistic assessments. In the following sections of this chapter, this concept is applied to account for the impact of all of the above listed factors of uncertainty. To illustrate, consider the peak demand forecasts. There are uncertainties associated with input assumptions to the baseline forecast other than temperature that have their own effect on the actual peak demand outcome, for example, level of economic activity. In other words, we can have two different peak demand forecast scenarios, each based on a different assumption about underlying levels of economic activity. Each of these two forecasts would still have a probabilistic range of uncertainty due to temperature's effect on peak demand.

Supply Adequacy Risk Assessment Results

The next sections present our quantitative assessments of the risks to 2003 California supply adequacy posed by some key uncertainties. Results are presented in the form of a table that shows the percent risk or chance that, under the stated conditions, there is insufficient capacity both to meet the peak demand and to maintain a seven percent capacity reserve. Literally, the risk information we present is the percent of the 300 Monte Carlo cases in which resulting available capacity was insufficient. In each of the 300 cases, we make random draws within a range of values for all of the following variables simultaneously: the effect of temperature variations on peak demand, the effect of hydrological conditions on the availability of hydroelectric generation capacity, the effect of potential construction delays on the availability of new power plant capacity, and the effect of aging on the rates at which generation and transmission facilities are forced out of service.

Results also include the value of the greatest deficit observed among all of the cases in which a deficit occurred. The maximum deficit values represent how much capacity would have to be added in a transmission zone to completely eliminate shortage risks, which, as previously discussed, has never been an industry objective. Closely evaluating the costs, benefits, and relative effectiveness of a variety of options for reducing shortage risk (i.e., new generation, transmission, efficiency, demand responsiveness) is a necessary step in determining what level of risk is deemed acceptable for a given transmission area.

Demand Reduction Uncertainties Affect Supply Adequacy Risk

This analysis examined the risk of having inadequate capacity supplies during 2003 under two of the peak demand forecast scenarios described in Chapter II-1. The differences between these scenarios are different assumptions for economic activity and consumer behavior regarding energy consumption. We selected the demand scenario considered most likely as our baseline. It is the demand forecast scenario labeled "slower growth in program, faster drop in voluntary" demand reductions We report the risk assessment results of the 300 Monte Carlo cases in **Table II-3-1** under the heading "Baseline Load." In addition, we selected the demand scenario with the highest demand (lowest persistence of recent demand reductions) for a second risk assessment. This is the demand forecast scenario labeled "no growth [in reductions] and drop in program [reductions], faster drop in voluntary [reductions]." This scenario was used as it presents the greatest risk of the three demand forecast scenarios from Chapter II-1.

Table II-3-1 shows that risks of shortages of power supply in California during the summer peak of the year 2003 vary from zone to zone. Under the Baseline Load scenario, the risk is zero or low in Southern California, LADWP, Northern California, SMUD and Central California transmission zones. In Southern California, 1.3 percent of 300 cases had inadequate capacity and the worst deficit was 1,700 megawatts. Risks are moderately high in the San Francisco, San Diego, and Imperial Irrigation District transmission zones. In San Francisco, 13.7 percent of the 300 cases had inadequate capacity and the worst deficit was 200 MW.

As expected, risks of shortages are higher under the High Load Scenario, although Northern California, SMUD and Central California still all show no risk of shortages. For Southern California, LADWP, San Diego and Imperial Irrigation District transmission zones, the risk of shortage more than doubles. Although the risk of having a shortage increases for LADWP, San Diego and Imperial Irrigation District, the magnitude of the maximum deficit does not. In Southern California, the risk of shortages of some magnitude is 4.3 percent, while the maximum deficit is 5,200 MW. San Francisco results don't follow the trend, showing lower risks in the High Demand than in the Baseline Demand scenario. This is due to chance effects and the limitation of our computational model--300 draws are insufficient to *guarantee* that the extreme outlying cases will always be part of the sample. It is safe to assume that risks of a shortage are increased in the San Francisco transmission zone under the High Demand Scenario, even if the maximum deficit does not change.

Table II-3-1.
Demand Reduction Uncertainties
Shortage Risks and Maximum Deficits by Transmission Zone
Summer Peak Period 2003

Transmission Zones	Risks (Percent)		Maximum Deficit (MW)	
	Baseline Scenario	High Load Scenario	Baseline Scenario	High Load Scenario
South CA	1.3	4.3	1,730	5,210
North CA	0	0	0	0
San Diego	7	17	3,030	3,540
San Francisco	13.7	11	230	210
IID	7.3	18.3	280	310
LADWP	0	0	0	0
SMUD	0	0	0	0
CCENT	0	0	0	0

The deficiency of capacity in certain California transmission areas contrasts with the total excess of capacity expected throughout the WSCC area as a whole. Without considering transmission constraints, the WSCC area could have an excess of about 20 gigawatts in summer of 2003. The existence of shortages means that transmission grid fails to deliver all necessary power to the deficient areas.

Table II-3-2 illustrates the probabilities of congestion for major transmission links within the WSCC area under our Baseline and High Load Scenarios.

Congestion for the transmission links inside and to California is expected during the summer peak of the year 2003. For several transmission links, the probability of congestion during this period is very high. It reaches 100 percent for Northwest- LADWP link for both Baseline and High Load cases. For the transmission link between Central and Southern California, it reaches 93.3 percent and 96.7 percent under the High and Baseline Load cases, respectively. Almost certainly Palo Verde- San Diego, Palo Verde- IID and Southern CA- IID links will be congested also.

The probability of congestion of certain transmission links does not demonstrate a definite pattern. As load changes between the scenarios, the power flows usually change not only in magnitude but also in direction. For example, the probability of congestion for the Southern Nevada- Southern CA transmission link is higher for the High Load case (77.0 percent) than for the Baseline Load case (63.0 percent). But for the San Diego- IID transmission link, the effect is the opposite: the probability of congestion is lower (45.7 percent) for the Higher Load than for Baseline Load case (59.3 percent.)

Our analysis of cases where shortages occur showed that the shortages were associated mostly with random draws of temperature effects that yielded higher than average peak demand. When extremely hot weather occurs in Southern California and in adjacent regions (Arizona, Southern Nevada) it may well happen that the whole Southern California region will be short of power because of the deficit of indigenous resources, congested transmission lines, or both factors. In this case, the Southern California transmission zone is short of resources by about 5 gigawatts and power supply from the adjacent areas is limited because of high local demand. On the other side, transmission lines connecting Central and Southern California are congested, which limits inflow of power from the north.

Normally, at peak load, the San Diego area is short of its own area resources by 2.0 to 3.0 gigawatts. Therefore, it strongly depends on import of power. During peak hours, San Diego imports power mostly from Southern California or Palo Verde. If the latter areas are also at higher demand and therefore have limited capabilities of exporting power, then San Diego is at risk of power shortages.

Table II-3-2.
Transmission Congestion is Expected in Summer 2003
Throughout the WSCC Area
Percent Risk of Congestion in Either Direction

Transmission Link	Probability of Congestion Percent	
	Baseline Case	High Load
Northwest- LADWP	100	100
Northern CA- Central CA	22.3	4.3
Northern CA- San Francisco	13.7	11
Southern CA- San Diego	12.7	12.3
Southern CA- IID	87.3	73
San Diego- IID	59.3	45.7
Central CA- Southern CA	93.3	96.7
Southern Nevada- Southern CA	63	77
LADWP - Southern CA	0	3.3
Palo Verde- San Diego	85.7	84
Palo Verde- IID	99.3	96
Palo Verde- Southern CA	35	46
Utah- LADWP	0	5.7

At peak load, San Francisco is short of its own area resources by up to 130 MW. Therefore, like San Diego, it strongly depends on import of power. Transmission capacity to San Francisco is limited, and in the cases observed when San Francisco peak load is high or local power units are out of order, San Francisco is at risk of a power shortage as has been experienced several times in recent years.

Obviously, it is an expensive solution to completely eliminate risk of power shortages, e.g., adding 5,200 megawatts of capacity in Southern California, an additional 3,500 megawatts in San Diego, 300 megawatts in IID and 200 megawatts in San Francisco. There are tradeoffs between certain levels of risk and the additional costs of reducing risk. A certain level of risk is acceptable, at least by a great majority of customers. Our analysis also suggests that there is room for reducing risks of power shortages by adding capacity to the most congested transmission links bringing power to the Southern California regions. This is an alternative or a complement to generation resource additions in these regions.

Aging Plants and Reduced Maintenance Increase Supply Adequacy Risks

For the previous decade, power plant construction in California has not kept pace with growing demand. Existing power plants take up the slack, many having been in operation for 40-50 years or longer. Aging power plant equipment may become less reliable, if sufficient maintenance expenses are not invested, and increase risks of forced outages.

To assess the impact of aging equipment on adequate power supply in California we conducted two sensitivity studies of our original Baseline Load scenario. In one study, we doubled the forced outage rates of thermal generating plants. In the other, we tripled them. These assumptions are not based on observed increases in historical forced outage rates. Rather, they are subjective changes made to assess the potential impact on supply adequacy risk, should such changes occur. Anticipating lower revenues from an energy market temporarily glutted with capacity could cause plant owners to spend less on unit maintenance or to reduce their availability for economic reasons. Of course, unit availability standards and reliability must run contract provisions would tend to counter this tendency.

Table II-3-3 shows the effect of increasing thermal generation forced outage rates on the risks of supply adequacy, by transmission zone. The probability of power deficiency increases substantially with the increase in forced outage rates. For example, in San Diego, if forced outage rates double, risk (probability of power deficiency) increases 4.3 times (31/7=4.3). If forced outage rates triple for the same region, risk increases 9.4 times (66/7=9.4). In Southern California, while forced outage rates double, risk increases 7.5 times (10.0/1.33=7.5); while forced outage rates triple, risk increases12.75 times (34.7/1.33=26). The same pattern is demonstrated for LADWP and IID: exponential growth of risks with the growth of the forced outage rates. In case of San Francisco, there is similar but slower growth in risk with increase of forced outage rates.

The impact of the forced outage rates, as the above table confirms, is also seen in the maximal power shortages observed. According to data in **Table II-3-3**, maximal deficit grows with forced outage rates. For example, in San Diego, it grows from 3,000 megawatts under the Baseline Scenario up to 3.64 gigawatts in the case of the maximum forced outage rate. The explanation of this observation is obvious. With lower reliability of the performance of the power plants, the probability of shortages is higher when simultaneously more power plants are off-line.

Table II-3-3
Aging Equipment and Reduced Maintenance Increase Supply Adequacy Risks
Shortage Risks and Maximum Deficits by Transmission Zone
Summer Peak Period 2003
(Includes only those regions where non-zero risk was observed)

Zone	Baseline Scenario		Double FOR		Triple FOR	
	Risk Percent	Deficit GW	Risk Percent	Deficit GW	Risk Percent	Deficit GW
San Diego	7.0	3.03	31.0	3.29	66	3.64
San Francisco	13.7	0.23	17.7	0.26	28.3	0.47
Southern California	1.33	1.73	10.0	4.44	34.7	8.0
LADWP	0	0	2.0	4.45	17.7	1.84
IID	7.33	0.28	33.7	0.5	67.3	0.6

In general, less maintained and aging equipment, or less reliable new equipment, can substantially deteriorate system reliability and can become a significant threat to the adequate power supply in California. The Unit Availability Standards program of the California Independent System Operator expressly seeks to manage this risk. The success of that and similar programs can avoid significant supply adequacy risks.

Construction Delays Affect Supply Adequacy

The timely addition of new generation and transmission resources is critical to managing the risk of supply adequacy. Delays in construction can impact power supply capability to meet California power demand. We assessed the potential impact of power plant construction delays on adequate power supplies for California by developing completion status categories and assigning new power plants projects to each category. Each category is assigned probability of getting power plants on line timely. Based on interviews with Commission Staff engaged in our permitting activities, we assigned each new power plant project to one category.

Five categories characterize the status of new power plant projects, as follows:

1. Under construction or recently completed
2. Regulatory approval received
3. Application under review
4. Starting application process
5. Press release only

We compared the risk of supply shortages in our original Baseline Load scenario to two sensitivity cases in which we assumed increasing construction delays. **Table II-3-4** illustrates the difference in assumptions among the Baseline Scenario, a Moderate Delay case, and a Pessimistic Delay case. The Baseline Scenario, used throughout this chapter, assumes reservedly optimistic probabilities of project completion. The Pessimistic Delay case assumes no new power plants are built (or partially built but not completed, or built but not run) and is admittedly an unlikely outlying case.

Table II-3-4
Construction Delay Input Assumptions
Probability that a Power Plant Comes Online, By Current Construction Status

Status	Baseline Scenario, Percent	Moderate Delays, Percent	Pessimistic Delays, Percent
Under construction	90	90	0
Regulatory approval received	70	50	0
Application under review	50	10	0
Starting application process	30	0	0
Press release only	10	0	0

Table II-3-5 illustrates the results of the three cases we considered to evaluate the impact of delays in construction. In comparing shifts from Baseline to moderate to pessimistic cases, both the risks and maximum deficit values grow. Not unexpectedly, delays in construction negatively affect the balance of power supply for California, but by different amounts in different regions.

Table II-3-5
Construction Delays Increase Supply Adequacy Risks
Shortage Risks and Maximum Deficits by Transmission Zone
Summer Peak Period 2003
(Includes only those regions where non-zero risk was observed)

Region	Baseline Scenario		Moderate Delays		Pessimistic Delays	
	Risk Percent	Maximum Deficit GW	Risk Percent	Maximum Deficit GW	Risk Percent	Maximum Deficit GW
Southern California	1.3	1.7	4.67	3.4	24.3	5.3
San Diego	7	3	14.7	3.2	71	4.2
San Francisco	13.7	0.2	15	0.3	26.7	0.4
Imperial Irrigation District	7.3	0.3	16.3	0.3	60.7	0.5

What we have described as a moderate delay more than doubles the supply adequacy risk for San Diego, Southern California and Imperial Irrigation District areas to 15 percent, 5 percent and 16 percent, respectively. The maximum deficits for these transmission areas are 3,200 megawatts, 3,400 megawatts, and 300 megawatts, respectively.

In the Pessimistic Delay (worst) case, the values of risks reach the levels at which almost certainly some regions will be short of resources: for San Diego the risk is 71 percent and Imperial Irrigation District, 61 percent. The risk of power shortages is also high in other regions. The maximum deficits of power may reach 5,500 megawatts in Southern California and 4,200 megawatts in San Diego.

These results of either the Moderate or Pessimistic Delay cases suggest the importance of bringing planned new power plant additions online in California as scheduled.

Where Do We Stand If Reserves Higher Than 7 Percent Are Desired?

Our previous analyses were based on an assumption that the desired operating reserve margin was seven percent--the level below which a normal performance of the power system is not possible. This level constitutes the minimal requirement for the power system to avoid alert signals from ISO being issued. Normal performance requires some additional “breathing space” for ISO to provide a reliable power supply to its customers. There are other considerations that favor a larger excess of capacity available in the power system. The point has been made that a well functional power market requires 30 percent to 40 percent of extra capacity in the system to provide a healthy energy price competition. This section simply illustrates just how far the California market is from being able to maintain a 30 percent operating reserve, and which transmission areas are closer to such a target (were it to become one) than others.

Table II-3-6 compares the supply adequacy risk and maximum deficits between our original Baseline Scenario and the same scenario but with an operating reserve target of thirty rather than seven percent. Shifting the requirements toward higher reserve margin increases probability of deficit, given the same amount of resources and demand. The main Southern California regions will not be able to provide a 30 percent reserve margin. It means that if a competitive market requires excess of capacity of 30 percent or more, it can not be achieved by 2003, unless measures beyond the currently proposed generation projects can be implemented to make an additional 10,000 to 15,000 megawatts of supply or demand reduction available to California.

Table II-3-6
Higher Reserve Targets are Harder to Hit
Shortage Risks and Maximum Deficits by Transmission Zone
Under 7 percent and 30 percent Reserve Targets
Summer Peak Period 2003
(Includes only those regions where non-zero risk was observed)

Reserve Margin, Percent	7	7	30	30
	Probability, Percent	Max Deficit, MW	Probability, Percent	Max Deficit, MW
Southern California	1	1,700	100	10,300
San Diego	7	300	100	3,500
San Francisco	14	200	17	700
Imperial Irrigation District	7.3	300	0	0
Los Angeles	0	0	100	2,200

The opposite relation with IID can be explained by changes in power flow pattern. Since IID consumes relatively small amount of power (less than 300 megawatts in most cases observed), this anomaly does not change the total trend.

Conclusions

Generally, the power system is said to have adequate capacity if it has enough generation and transmission resources to meet the customer demand and to maintain a reserve of capacity for contingencies. But it would be prohibitively expensive to build an electric generation and transmission system that would *never* experience a service outage. Instead, we seek to minimize outages within a constraint of reasonable cost, thereby accepting some risk of outages.

The analyses conducted for the year 2003 show that there is no single way of determining whether or not California will have adequate capacity. With all current resources in operation and with the expected new resource additions, California has enough power to meet a forecasted demand in a year 2003, on average. But California may face a rather rare combination of unfavorable circumstances that could bring risks of power supply shortages (in the form of lower than required reserves or even outages.)

Risks of power supply shortages vary for different parts of the state: from little to no risk for Northern and Central California and the largest municipal utilities- LADWP and SMUD, to low risk (1.3 percent) for Southern California, to a noticeable level of risk (7 percent) for San Diego, and to a significant level of risk (13.7 percent) for San Francisco.

Aging equipment, resulting in an increase of forced outages of power supply equipment, increases supply adequacy risks. Sensitivity studies show that risks of power shortages increase much faster than forced outage rates of the power supply equipment (e.g., in Southern California, when forced outage rates double, risk increases 7.5 times; while forced outage rates triple, risk increases12.75 times.)

Construction delays negatively affect supply adequacy, increasing risks dramatically. This suggests the importance of bringing planned new power plant additions online in California as scheduled.

The main Southern California regions will not be able to provide reserve margin at the level of 30 percent. It means that if a competitive market requires excess of capacity of 30 percent or more, it can not be achieved by 2003, unless measures beyond the currently proposed generation projects can be implemented to make an additional 10,000 to 15,000 megawatts of supply or demand reduction available to California.

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1. [1] The original near-term supply outlook for the years 2002-2004, which appeared in the November 2002 Staff Draft of this report and on which this work is based, has been updated for this final version of this report. This work does not reflect those updates. However, the result of this work still remain illustrative of the uncertainties involved, even if the probability and magnitude of supply adequacy risks might be different.

Part III: Issues Analyses

This section presents analyses of five issues important to the development of a workable electricity market. Chapter III-1 deals with the fundamental question of whether the existing energy market can maintain the electricity system adequacy at reasonable prices, and what market changes might better achieve that goal. Chapter III-2 provides an assessment of future retail electricity rates by utility and customer class, showing how each component of costs contributes to the total rate. Chapter III-3 examines the characteristics of the demand response potential, and suggests a specific mix of load curtailment programs to ensure reliability in the year 2002. Chapter III-4 discusses how the current *ad hoc* market arrangements affect the renewable generation industry and issues related to incentive programs for developing renewable generation resources. Chapter III-5 describes the progress the Energy Commission has made in licensing new power plants, issues that may affect the ability of power plant developers to obtain timely approval; and measures needed to address these siting issues.

Chapter III-1 Electricity Markets and Capacity Supply

Introduction

While the supply-demand outlook is reasonably resilient for the near future, many issues need to be resolved to establish a reliable, reasonably-priced, efficient and sustainable electricity system. The current market structure is an "ad hoc" arrangement, pieced together to respond to the numerous short-term crises. These crises revealed fundamental problems in California's overall system. Unless modifications are made, by 2005 California will be headed back into supply and demand conditions likely to produce tight supplies, price volatility, reliability concerns, and consumer dissatisfaction. Policy-makers now have to choose what market structures will best serve California.

As described in Part 1, tight supplies were one of the principal conditions that allowed the California market to destabilize. Choosing a method to ensure future adequate supply is a major element of the 2002 market redesign.

This chapter examines what structure will motivate the addition of timely new supply to reduce price volatility and contribute to reliable service. Three options for revising the supply market for capacity are introduced and evaluated. [1] In addition to introducing a method to ensure capacity, modifications to retail pricing and to the wholesale market are also necessary for a sustainable generation market.

Problem With Current Market Design

A deregulated market depends on good market design to encourage private developers to profit from providing sufficient power. In a competitive wholesale market, electricity generators are not obligated to build to meet load. Since there is no separate payment for capacity, the amount of profit generators receive depends on expectations regarding the wholesale price of energy and ancillary services. When the expected wholesale price of power is high, independent power producers will build new plants. However, because of two- to four-year lead times inherent in siting, financing, and constructing multi-million dollar facilities, the response to prices will lag. Boom-bust cycles and price spikes are the result.

California's market design was supposed to send correct price signals through its energy and ancillary service markets. Independent power generators and energy service providers would see a profit opportunity and invest private capital. The theory was that profit incentives would be strong enough that people would build enough generation to meet capacity needs as well. New generators could always see a profit potential by under-cutting the costs of other generators and older units. The more competitors there are, the more excess generation and the more likely that lower prices will occur.

Unfortunately, this theory would not work if other market rules were weak or susceptible to gaming. It also wouldn't work in a California market inset into a larger regional market with a different set of rules. And, as Part II showed, generators cannot earn enough money in highly competitive markets given California's spikes of demand in only a few hours of the year.

Generators did see a profit opportunity, and the Energy Commission was inundated with applications for new plants. But, these units didn't come on line fast enough to alleviate the 'bust' conditions of very tight supply in 2000. In this scheme, the amount of generation will be 'just right' in the long-run, but in the short-term there will always be too much or too little for stable prices. To smooth out the tendency to over-build or under-build, we need a system to acquire capacity as a product in its own right.

Since no one has been able to design a purely competitive market, all real world markets have required high levels of market monitoring and administrative intervention to correct unforeseen problems that emerge. To some extent this fine-tuning was expected, but California's problems extend far beyond what was anticipated. This introduces a high level of regulatory risk and a fluid market design, which make it difficult for everyone to plan in their long-term best interest.

Two remedies are needed - an appropriate market structure and effective market monitoring and antitrust guidelines for electricity markets. The purpose of market monitoring would be to limit manipulation of the wholesale electricity market. Price volatility could be restricted, but price variation would be adequate for sending market signals.

Supply Side Approaches to Generation Adequacy

Three supply designs are under active discussion in California to ensure sufficient investment and system reliability: incentive payments for reserves, installed capacity requirements and a regulated, cost-of-service capacity reserve. These options are summarized below, then their strengths and weaknesses are explored.

Incentive Payments for Reserves

This approach makes payments to generators for providing reserve capacity, without requiring a specific level of reserves. This mechanism is quite complex, in that there is a great deal of choice as to how to set the payment. These capacity payments may consist of either a fixed amount of money per megawatt of capacity or a variable payment, increasing and decreasing with the reserve capacity of the system. The purpose of a fixed capacity payment is solely to incent new generation, while the purpose of a variable capacity payment is to encourage capacity reserves by providing incentives for generators to keep capacity available during periods of excessive demand. The system operator or regulator may make this payment in every market settlement period - either to generators that have actually been dispatched, or to any available generator; or on a yearly basis - to all generators. Finally, the payment may be given to all capacity or only to generators coming on-line after this mechanism is put in place.

Installed Capacity Requirements

In this method, the load-serving entity, e.g., a utility or energy service provider, is required to own or contract for sufficient capacity to serve both demand and reserves. Currently, the PJM (Pennsylvania, New Jersey, Maryland), New England, and New York power pools follow this approach. Retail suppliers may operate their own generating capacity, purchase rights to generation owned by third parties, or buy capacity rights from a spot market for installed-capacity to meet any shortfalls. Should a retailer fall short of the mandated reserve margin, it is subject to an installed capacity deficiency charge. Theoretically, as long as it is set higher than the average cost of building new capacity, the installed-capacity deficiency charge will encourage loads to acquire the level of generation capacity deemed necessary by the system operator.

Regulated Cost-of-Service Capacity

The regulated wholesale market uses governmental oversight to pay for capacity. This could be done by reverting to an integrated monopoly industry or by shifting responsibility for acquiring capacity to government. In order to return to a completely regulated wholesale market, investor-owned utilities would need to once again control electric generation, transmission, and distribution services. In the government management approach, reserves would be owned, maintained and paid for by ratepayers or taxpayers and only brought on line when necessary for shoring up reliability or to reduce price spikes.

Advantages and Disadvantages of Alternative Wholesale Market Structures

The remainder of this chapter evaluates alternative wholesale market structures with respect to supply adequacy, average retail price, stability of retail price and level of regulatory oversight required.

Incentive Payments for Reserves

The only example of its use is that of the United Kingdom (UK) from March 1990 to March 2001. In this system, the price each generator received for energy was the sum of two components, the system marginal, or bid, price, and a capacity payment. The capacity payment was calculated as loss of load probability, multiplied by the value of lost load, minus system marginal price. During peak-demand periods, generators also received a payment for capacity they made available, whether it was dispatched or not. The system implemented this payment to encourage capacity to be made available when it was the most needed.

This system does not function as intended when generators possess market power. The UK market structure was such that both National Power and PowerGen found it profitable to withhold generating capacity during peak demand periods. Doing so enabled them to inflate the loss-of-load probability component of the capacity and availability payments, resulting in excessive wholesale power prices. Additionally, the availability and capacity payments were intended to incent new generation. As capacity became short, loss-of-load probability would rise, and with it so would capacity and availability payments, and thus the wholesale price of power. As this happened, generation would be more profitable and more power plants would be built. This approach backfired in 1991 through 1995 and 5,000 MW of net capacity was retired in England and Wales. Because low reserve margins are associated with high capacity and availability payments, the generators had the incentive to retire net capacity to receive higher prices. Due to the problems involved in this system's operations, England abandoned it March 2001.

This structure yields higher average retail price than the purely competitive market, because the incentive payment may be higher than needed or because it induces generation adequacy levels beyond what some consumers would pay if they had a choice. However, it is generally not possible to compare its average price with that of mandated reserve margins. Because generators may manipulate this system, it yields excessive variability in retail prices. Since this structure is especially susceptible to manipulation, it places great strains on regulators' ability to police it.

Installed Capacity Requirements

The basic idea of an installed capacity requirement is simple. Instead of setting market rules in such a way that an intersection of demand and supply yields a price which sets the amount of capacity, a specific party – the load-serving entity – is tasked with the responsibility to acquire reserves. The system operator, subject to regulatory approval, is tasked with setting the minimum amount of reserves to be acquired. The load-serving entities are allowed to meet this requirement through a combination of short-term and long-term resource options and to pass the costs on to their ratepayers.

This approach is proposed if the market cannot set a market clearing price for capacity or if the market solution produces price variations which are unacceptable.

The two main advantages of an installed capacity market are that there is greater certainty regarding reserve capacity than in a purely competitive market and energy prices are less volatile. In setting the capacity requirement, the system operator can control the amount of generation present. Because price spikes are associated with low reserve margins, this system will generally have less volatile prices than the purely competitive market.

This structure relies on administratively set levels, not prices, to incent new capacity. If regulators set the requirement too low, the market will not have sufficient reliability. If they set it too high, then the cost of electricity will be higher than it needs to be. Setting the level requires both confidential, market-sensitive information and an open public process. This is time-consuming and difficult work; hence it will lag behind emerging market conditions. And, a separate market for the exchange of capacity rights means that the regulatory agency has another market to monitor for the exercise of market power. This may tax the capability of regulators.

Another drawback is the way a California installed capacity requirement would interact with other western markets. As Steven Stoft has noted,[2] the price of electricity in the installed capacity market will generally not spike as high as other markets during times of high demand. Because electricity markets are interconnected, system operators compete with each other for electricity. When outside prices rise high enough, generators will be willing to pay the California capacity deficiency charge, because they stand to reap a greater reward for doing so. Even though the installed capacity market may have sufficient generation to meet its own needs, it will lose it as wholesalers export energy to markets with higher prices. This competition then causes the mandated reserve market operator to raise prices, in an attempt to attract the power necessary to meet its needs. Often, they are forced to import power at high prices, even though they have sufficient capacity in their region. As enough system operators follow this practice, competition inflates prices.

Efficient reserve margin levels differ depending on the underlying market structure. A reserve margin necessary to meet unresponsive demand is too high for a responsive market, or one with efficient pricing rules. Average retail prices are not only higher for this market structure than for the perfectly competitive market, but they will also be determined by the reserve margin the regulator chooses. Hirst and Hadley[3] note that the required reserve margin that yields the lowest system costs depends on the degree to which consumers respond to changing electricity prices. This means that it is difficult to set the capacity requirement efficiently. Hundreds of millions of dollars are at stake in setting the reserve level.

Choosing to assign load-serving entities the responsibility for acquiring load sets a broad framework. But the actual impacts are dependent on such choices as the level of reserve to be acquired, how far in advance reserves must be required, the options available to meet the requirement, penalties for non-compliance, and responsibility for paying the costs.

Regulated Cost-of-Service Capacity

This category covers two options: returning investor-owned utilities to a regulated monopoly or a permanent government role in obtaining capacity in a hybrid market. Municipal utilities such as Sacramento and Los Angeles have maintained the regulated cost-of-service approach. Moving back to a regulated market for investor-owned utilities would not be easy, and probably not possible. The first, and perhaps most contentious step would be to reestablish the utilities in a vertically integrated structure. This would mean buying back all generation divested by the utilities. As both SCE and PG&E are financially distressed, they are currently not capable of repurchasing generation. Economic conditions in the state would not allow them to do so. Even if either of these entities possessed the capability, the utilities sold this generating capacity to independent power producers at several times book value. A vertically integrated utility would not be able to recoup the cost without raising retail rates substantially.

As Kellan Fluckiger has noted,[4] in the regulated wholesale market structure, utilities have an obligation to serve and a related obligation to build capacity. This makes supply adequacy the greatest strength of this structure. Under the traditional regulated structure, the utility earns a regulated rate of return on investment. Therefore, it does not have as much incentive to keep costs down by avoiding investment that would be unprofitable in an unregulated market.

Stability of retail prices is another strength of regulation. As opposed to market forces determining prices, regulators must approve of any rate increase requested by a utility. The CPUC has been cautious about granting rate increases to utilities, accounting for stable, predictable electricity rates. Of course, the behavior of regulated utilities is monitored closely. By definition, regulation implies a high level of oversight.

The second option is permanent government involvement in the capacity market. If the state decides to participate in the market for generation, it could exercise considerable control over the amount of generation coming on-line. Such cost-of-service reserves whether owned by the state or by utilities could stave off the impending price spikes for the 2002-2004 time frame but would also have the undesired outcome of driving out private investment. Eventually, this will lead to inadequate generation and price spikes. Therefore, if the state chooses to go this route, it must make a long-term commitment to sustained investment in the power market in order to achieve the desired result.[5]

With cost-of-service peaking capacity, initially there is a reduction in price increases, but later prices tend to increase again. According to research by Dr. Stephen Lee, there seems to be a narrow range of participation by the power authority in supplying peaking capacity, beyond which the private investors may permanently defer future capacity investments.[6]

It may be desirable for the state to wait until the uncertainty surrounding the wholesale market structure in California is resolved before taking this plan of action. While state-owned generation would lessen price volatility in a purely competitive market, it would be counter-productive in an installed capacity requirement or installed capacity payment structure.

Retail Design for Supply Adequacy

The success of any wholesale market structure depends on coordination between the wholesale and retail market. If retail prices are not flexible, while wholesale prices are, disastrous consequences in the wholesale market can result. In any of the competitive wholesale markets of this chapter, price will rise as reserve margins fall. Retail power suppliers must then buy power at this higher price. If retail price is flexible, they will raise their rates accordingly. This would send a signal to consumers that power is scarce, and there are rewards for reducing consumption. As consumers adjust demand, reserve margins level off, and the severity of price spikes is alleviated.

Real time pricing is a highly effective weapon in solving the power crisis. When near the limit of supply, small changes in demand make large changes in price, dampening price volatility.

Having electricity prices respond quickly to short-term or real-time market fluctuations is essential to bringing about a functional market where supply and demand could meet, at least at the wholesale level. However, excessive price volatility is not needed to provide incentive for generators to build sufficient capacity.

Real-time pricing alone would not be sufficient. There is a role both for real-time pricing and other demand-side programs, such as incentive programs for conservation, public appeals for conservation, payments to consumers to reduce their peak demand, and the use of interruptible loads as additional real-time measures by the ISO to balance supply and demand.

In the current market, consumers are not able to respond to changing prices. They lack this ability due to inflexible rate designs, despite the fact that AB1X-29 paid for the installation of real-time meters for thirty percent of the end-use load. With a fixed retail price, during peak-demand periods suppliers are forced to try to meet all of the increased demand, which can place great strains on their generating capacity. This puts greater upward pressure on wholesale prices, as generators must use increasingly costly generation to meet extra demand, and the resulting decrease in reserve margins facilitates gaming of the power market, as power generators may charge inflated prices without facing a reduction in demand.

While allowing some customers to face real-time pricing and allowing others to choose a stable price is desirable, if ill done, bifurcating the retail rate designs could be interpreted as fostering cross-subsidies. However, consumers who preferred stable prices should have the option to sign up for such programs with a hedging entity, e.g., the distribution company, provided that no cross-subsidy was used. This would mean that in return for the price stability, the reduction of risk would be accompanied by a higher average price. This would not be a violation of market principles.

Any generation market will be more effective if California flattens its summer demand spike, so that too much generation isn't trying to make money in the highest 100 hours of the year. A more even annual profile will reduce the boom-bust cycle, give generators more hours to compete and a better chance of recovering costs, and will require fewer generators.

Wholesale Market Design and Supply Adequacy

Good market design is necessary for generation adequacy. Generation adequacy will be facilitated if the forward and real-time markets are consistent with real-time operation requirements. The markets should use commercial models that reflect physical constraints and efficient dispatch. Generators must have an obligation to perform according to schedules and dispatch instructions. Accurate locational prices, while preventing exercise of locational market power are also needed.

On a broader scale, the Bay Area Economic Forum[7] argues that California should advocate the regional transmission organization process, and be a leading figure in the formation of RTO West. By coordinating operations and long term planning across the entire region, it argues, transmission bottlenecks can be better eliminated and generation resources more economically shared across the region. Through coordinated planning, Western states could develop a common set of rules for incenting the construction of new transmission lines within and across their states. This would provide additional options for California in preventing power crises in the future.

Conclusions

The current market structure must be changed because it cannot provide adequate generation in a timely, efficient and sustainable manner. Under the current market structure California is doomed to boom and bust cycles of power plant construction, price spikes, price volatility, and higher prices. All this is due to necessary hedging against the risks inherent in a faulty market design.

A good market design will provide benefits to consumers and suppliers, allow for efficient market monitoring, reduce the need for government intervention, and promote competitive innovation. No market design is perfect; all involve tradeoffs. Decision-makers need to define the market's objectives and the attributes that are important.

The market structure must be compatible with other market designs in the Western United States. California is an integral part of a regional market.

Decision-makers need to assess the strengths and weaknesses of each market structure in setting a course. Further exploration is needed to determine the most effective capacity payment options: implementation of capacity surcharges tied to energy purchases, requiring loads to obtain reserve capacity, government intervention through purchase of facilities or contracts, or utility ownership of reserve capacity.

A required reserve structure yields less variable prices, but has higher average prices. It is also more difficult to monitor, as it contains two separate markets - one for reserves and another for capacity. A cost-of-service design drives out private investment and requires an ongoing commitment of regulated funding from loads. It shifts the risk from generators to ratepayers.

The wholesale and retail market structures are interdependent. Effective generation price signals cannot take place independent of the retail market.

Consumers must choose to consume or not consume based on prices that reflect market conditions. They may make this choice either directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability.

Generation adequacy will be facilitated if the wholesale day-ahead, hour-ahead, and real time spot markets use commercial models that reflect physical constraints and efficient dispatch. Generators must have an obligation to perform according to schedules. Accurate locational prices are needed.

A coherent market design will need to be advocated in multiple forums, including FERC, the ISO, CPUC, CPA, and DWR. New California laws will be needed to facilitate a new design and to replace the many short-term fixes that were legislated to handle immediate crises. While needed at the time, such approaches may be counter-productive in a redesigned market.

Endnotes

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1 For purposes of discussion, the markets are divided into three: generation supply, wholesale pricing (energy, capacity and ancillary services markets), and retail consumption.
2 Notes from: “Power System Economics," presentation at the CEC November 7, 2001 workshop, Exploring Alternative Wholesale Electricity Market Structures for California.
3 "Maintaining Generation Adequacy in a Restructuring U.S. Electricity Industry," Oak Ridge National Laboratory, October 1999.
4 Presentation at the CEC November 7, 2001 workshop, Exploring Alternative Wholesale Electricity Market Structures for California.
5 Dr. Andrew Ford, “Propensity of a Competitive Power Market Towards Boom-Bust Cycles- Theory and Insights”, research paper presented at Energy Commission November 7, 2001 workshop, Exploring Alternative Wholesale Electricity Market Structures for California.
6 Dr. Stephen Lee, “Comparison of a Competitive Wholesale Power Market with Alternative Structures through a Long Term Power Market Simulation”, research paper presented at the CEC November 7, 2001 workshop, Exploring Wholesale Electricity Market Structures For California.
7 Ibid.

Chapter III-2 Retail Electricity Price Outlook

Introduction

This chapter presents the Energy Commission outlook of electricity retail rates for California Investor- and Publicly-Owned Utilities for the years 2002-2012. In this outlook, the Commission provides estimates of the retail electricity rates that typical consumers may pay, given projected energy prices, utility plans and programs, and regulatory decisions.

Under the circumstances specified in this chapter, retail rates for investor-owned utility (IOU) customers will most likely increase in the 2002-2003 period. A rate decrease is unlikely, unless the Federal Energy Regulatory Commission (FERC) orders merchant generators and energy traders to refund the State utilities for overcharges incurred during the fall 2000 and the winter 2001. However, a small rate decrease is possible after 2003 for most IOU customers. Municipal utilities are likely to maintain constant retail electricity rates for their customers during the 2002-2003 period. Rates for municipal customers after 2003 would most likely reflect the utilities' cost of generation, which under current projections will increase slightly every year through 2012.

The electricity rate outlook serves as a useful baseline for electricity consumers, market participants, regulatory decision-makers, and government agencies. This outlook is not an absolute prediction of what the future electricity rates will be, since future regulatory actions, technology development, or market changes may alter key fundamental assumptions. The projection uses the best available information and a set of assumptions the authors believe probable and realistic. However, many factors influence prices. This outlook provides consumers, market participants, and policy makers with a basic understanding of the determinants of future electricity rates.

The IOUs covered in this section are as follows:

- Pacific Gas and Electric Company (PG&E)
- Southern California Edison Company (Edison)
- San Diego Gas & Electric Company (SDG&E)

The Publicly-Owned Utilities (municipal utilities) include:

- Los Angeles Department of Water and Power (LADWP)
- Sacramento Municipal Utility District (SMUD)
- The City of Burbank Public Department (Burbank)
- The City of Glendale (Glendale)
- Pasadena Water and Power (Pasadena)

Retail electricity rates detailed in this chapter reflect the best available information to Commission staff up to mid-November 2001. Since then, the California Public Utilities Commission has rendered some decisions that have a direct impact on the IOU price outlook. In addition, Southern California Edison provided comments and data to Commission staff that could also change the outlook. The Commission has directed the staff to incorporate relevant data and information in an update of retail electricity prices within the next two months.

Background on Investor-Owned Utilities

As noted in Section 1, AB 1890 mandated a restructuring of the electricity industry based on the implicit assumption that electricity prices for consumers would eventually decline. Some of the changes that AB 1890 instituted to restructure the market included a transition period, recovery of uneconomic costs for IOUs, competition transition charges in electricity rates, overall rate freeze, buy/sell energy requirement for IOUs, trust transfer amount charges in rates, and public purpose programs costs. Although electricity rates increased instead of declining, some of these cost charges or features of the market still persist four years after the initiation of restructuring.

The transition period from the regulated monopoly to a market structure in which electricity could be sold and purchased in a competitive market started January 1, 1998. It was suppose to end no later than March 31, 2002. However, if an IOU recovered its uneconomic costs associated with power plants (sunk costs of generation) prior to March 31, 2002, then the transition period could have ended sooner for such an IOU, as was the case with SDG&E, which recovered its stranded costs by June 30, 1999. At that point, the utility would charge the entire energy costs to its customers. Given the chaotic energy prices during the fall 2000 and winter 2001, the transition period to a fully competitive wholesale and retail electricity market practically does not exist anymore.

Uneconomic asset costs, also known as stranded assets, are the costs that investor-owned and municipal utilities incurred on behalf of their customers. For example, years ago when the investor-owned utilities were fully regulated, they built power plants and entered into long-term agreements with independent generators to provide power for their customers. They planned to recover their investment and costs of long-term agreements through the electricity rates. Most of the time, those plants and contracts, at the initial time of restructuring, could not compete economically with modern power plants. Therefore, the extra costs were considered "stranded." Regulators in California divided stranded assets into uneconomic sunk costs of generation (for power plants) and uneconomic costs of long-term contracts and obligations. According to AB 1890, the utilities could recover uneconomic sunk costs of generation by March 31, 2002 and uneconomic costs of long-term contracts and obligations until their termination.

The competition transition charge (CTC) was instituted as a non-bypassable charge in the IOU electricity retail rates that reimbursed utilities for their uneconomic asset costs mentioned in the previous paragraph. However, because of the high prices of energy during the fall 2000 and winter 2001 and the rate freeze, this charge became negative in late 2000 and early 2001.

Rates for IOU customers during the transition period were frozen at a 1996 level. Because of the rate freeze, the IOUs could not pass along the higher cost of energy to their customers. As a result, the IOUs accumulated a large amount of debt due to revenue undercollections. The rate freeze continued until early January 2001 when the CPUC increased the rates by an average of one-cent and another three cents in May. Commission staff has assumed in this forecast that customers would pay for these undercollections in future electricity rates.

The IOUs covered in this report sold most of their fossil generating plants to other companies during the transition period. However, they still own hydroelectric, nuclear, and out-of-state coal power plants. Nevertheless, according to rules of restructuring, the IOUs were obligated to buy and sell all their power to the PX and the ISO during the transition period. Because of this requirement, the IOUs were unable to enter into power contracts or hedge on their energy costs.

The trust transfer amount (TTA) charge represents the costs of financing bonds needed to fund the ten-percent rate reduction that residential and small commercial customers received during the rate freeze period. Residential and small commercial customers have the obligation to pay this charge to redeem the bonds. The charge will remain in these customers' bills through the year 2007.

Current law (AB 995 and SB 1194) provides authority through the year 2012 for the collection of a non-bypassable system benefits charge to fund public purpose programs primarily dedicated to research development and demonstration, renewable energy resources and energy efficiency. This charge is currently included in the rates.

Background on Publicly-Owned Utilities

Although the IOUs were obligated to comply with the electricity restructuring rules as determined by the law, municipal utilities had the option to participate freely in all aspects of restructuring. For example, municipal utilities were not required to buy or sell power or ancillary services to the Power Exchange (PX) or the Independent System Operator (ISO). Since municipal utilities were not obligated to participate in the ISO activities most decided not to join the ISO. Some, such as SMUD and Pasadena, decided to join after a few months, but are currently considering dropping their participation.

AB 1890 did not require municipal utilities to allow direct access (retail competition) within their service territory either. However, some municipalities allowed limited direct access (SMUD), while others established target dates for direct access. A few municipal utilities have not disclosed their plans to establish direct access. Because of poor participation, a limited number of energy service providers, and higher energy prices, most of these utilities have indefinitely deferred their direct access programs.

At the beginning of restructuring, most municipal utilities also had uneconomic asset costs resulting from old power plants and long-term contracts and obligations. For example, SMUD imposed a CTC charge on customers that selected other electricity suppliers to recover its uneconomic costs. Glendale imposed a 1.7 cents/kWh CTC charge on its customers. LADWP froze its rates through 2001. The other municipal utilities increased their rates at various dates starting in 1996. Today most of these utilities have changed their rates to adjust for the 2000 and 2001 energy purchase cost. Their assets, which were considered stranded prior to restructuring, became economic and profitable during the energy crisis. As a result, LADWP currently has the lowest rates in Southern California and could maintain that position for the next ten years. Although SMUD used most of its rate stabilization fund during the crisis, the utility still maintains the lowest rates in Northern California.

Even though many had uneconomic assets from long-term investments in the 1980s and 1990s, most municipal utilities chose not to formally recoup this investment through a government-approved CTC charge by joining the ISO. To create a reserve to offset the costs of uneconomic assets, each decided to accumulate excess electricity revenues in rate stabilization fund accounts. As early as June 1997, Pasadena reported a $31 million balance in their rate stabilization fund. Likewise, SMUD reported a $90 million and LADWP a $815 million balance in a similar fund accounts. Burbank and Glendale were reported to have plans for accumulating $73 and $174 million, respectively, in rate stabilization funds by July 2003. Most of the municipal utilities, except for LADWP, used up these accounts to finance expensive energy they purchased in the open market in late 2000 and early 2001.

LADWP, Burbank, Glendale and Pasadena had some uneconomic assets from expensive investments and contracts with the Intermountain Power Project (IPP), Palo Verde Nuclear Generating Station, Bonneville Power Administration, Portland General Electric, Hoover, Montana Colstrip and miscellaneous other arrangements. As of June 30, 1999, LADWP estimated the value of its uneconomic assets at between $3.0 and $3.5 billion. The utility, however, lowered its stranded assets to $1.7 billion by August 2000 due to the power it sold in the PX and the ISO. In May 1998, Burbank estimated the value of its uneconomic assets at between $159 and $305 million. Although public information was not available for SMUD, Glendale, and Pasadena, Commission staff estimated that the last two utilities had uneconomic assets that were similar in magnitude as Burbank's. Although SMUD did not have expensive long-term contracts as the other municipal utilities, its rate stabilization fund was severely depleted late 2000 and early 2001 due to the higher costs of energy purchases in the wholesale market. Although not all of the municipal utilities included in this report shared the same commitments, the IPP and Palo Verde investments were common to LADWP, Burbank, Glendale, and Pasadena, which during the energy crisis became a valuable asset.

Method of Estimating Rates

With California's electric industry currently undergoing dramatic changes, electricity rates for IOUs and municipal utility customers have increased dramatically during the current year. For example, the CPUC approved two rate increases for the IOUs, a one-cent average rate increase in January and another three-cent increase in May 2001. Similarly, governing boards of municipal utilities have approved overall rate increases to replenish their rate stabilization funds and energy cost adjustments to recover their fuel and energy cost.

The California Public Utilities Commission (CPUC) is currently considering the Department of Water Resources (DWR) revenue requirements for energy purchases that the department contracted on behalf of the IOUs during 2001. The CPUC is also considering a number of IOU applications for rate changes that could affect future rates. Governing boards of municipal utilities could also make program changes that affect their rates.

To make retail electricity price projections for each utility and customer class, Commission staff:

- Reviewed current retail rates to establish a benchmark
- Evaluated customer profiles
- Developed assumptions and inputs
- Made projections

Table III-2-1 illustrates Commission staff's assumptions of a typical utility customer. The table provides monthly average electricity consumption, load factor, and demand for each customer type. Actual electricity characteristics of specific customers depend on many factors such as climate and type of facility, type of energy using equipment, and others. Commission staff assumptions may not match the IOU and municipal customer characteristics of a typical customer.

Table III-2-1
Monthly Electricity Used Typical Customer

	Residential	Small Commercial	Medium Commercial	Industrial	Agricultural
Usage kWh	500	1,241	21,862	735,305	5,093
Load Factor	NA	.47	.50	.83	.35
Demand kW	NA	3.6	60	1217	20 (27 HP)

NA: Not Applicable
Sources: Various IOU tariff schedules and municipal utility web sites.

The IOUs and municipal utilities usually divide their customers into residential, commercial, industrial, agricultural, street lighting, and other customer classes. Most of the customer classes contain several rate schedules. Utilities assign customers with similar consumption characteristics to a specified rate schedule. Some rate schedules have more customers than others. **Table III-2-2** provides the rate schedules used to represent each customer class. These rate schedules were used because they are the ones that reflect the most common characteristics of a customer class.

Table III-2-2
Rate Schedules Representing Customer Classes

Utility	Residential	Small Commercial	Medium Commercial	Industrial	Agricultural
PG&E	E-1	A-1	A-10	E-20P	AG-1 (B)
SCE	D	GS-1	GS-2	TOU-8	PA-1
SDG&E	DR	A	AL-TOU	A6-TOU	PA
LADWP	R-1	A-1	A-2	A-3	N/A
SMUD	R	GS-27	GS-47	GS-TOU	AS-63
Burbank	R	C	C	P	N/A
Glendale	L-1	L-2	LD-2	PC-1-B	N/A
Pasadena	D	G-1	P	P	N/A

Source: Various IOU tariff schedules and municipal utility web sites.

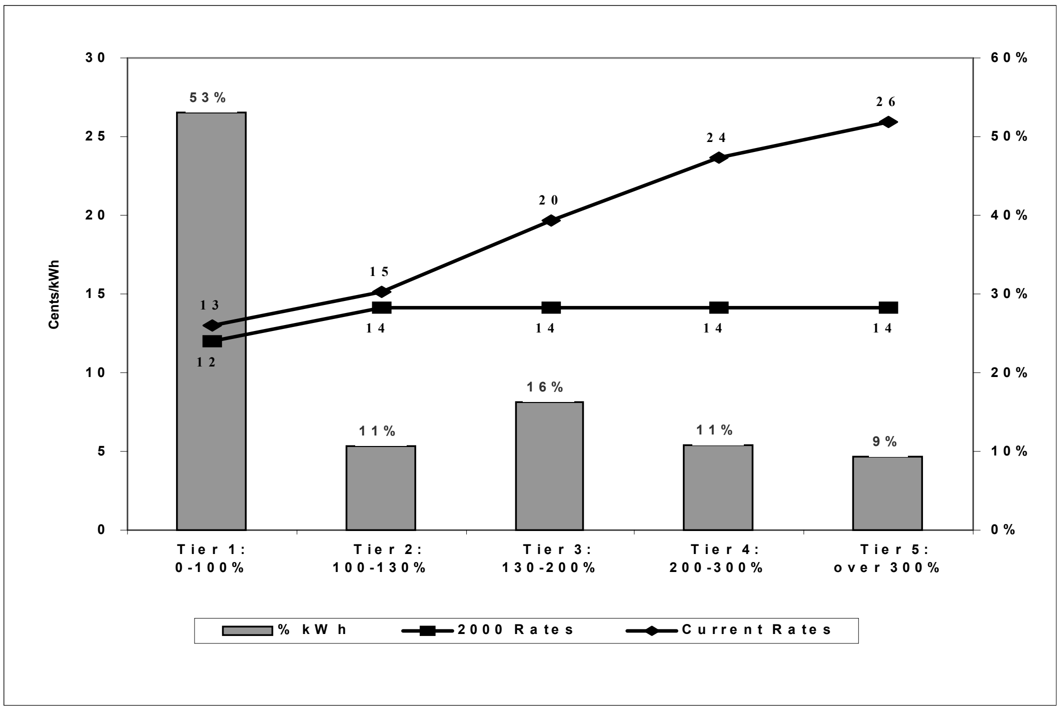
Investor-Owned Utilities

Commission staff estimated present rates for each customer class using existing tariff schedules and/or tariffs filed by the IOUs with the CPUC to reflect recent CPUC rate-making decisions. Once present rates were estimated, future rates were projected using adjustments for expected changes in authorized costs of service. These adjustments include generation and non-generation costs as well as non-recovered wholesale energy cost.

Generation Costs

The Commission staff used tariffed generation rates as a benchmark to estimate generation costs and then adjusted generation rates yearly for over- or under-revenue collections. Changes in generation costs were allocated among different customer classes using existing allocation methodologies applied by the CPUC in rate proceedings. An exception was made for residential consumption under 130 percent of baseline for the years 2002 and 2003, assuming that current legislative restrictions on cost increases for such level of consumption would be relaxed in 2004. **Figure III-2-1** compares electricity rates for 2000 to their 2001 rates for Edison's residential customers at different tiers of consumption. Residential customers that consume up to 100 percent of the baseline allowance received a one cent increase during 2001. However, if consumption increases up to 300 percent of baseline, the rate increases from 14 cents/kWh in 2000 to 26 cents/kWh. Similar price characteristics exist for PG&E's residential customers.

Figure III-2-1
Edison Residential Electricity Rates Percent kWh Over Baseline



Source: CPUC Decision D 01-05-064

Commission staff projected the costs of three generation components: 1) utility retained generation, which includes utility-owned power plants and contracts held by the utility, 2) Department of Water Resources contract costs, and 3) spot market purchases. Commission staff estimated the quantities of electricity from each source, then projected the cost of that electricity. The result of these three components, plus a 3.75 percent ancillary services adder for utility-retained generation and spot market purchases, established the forecast cost of generation to investor-owned utilities. This forecast methodology reflects oversubscribed DWR contract purchases as negative spot market purchases. In essence, Commission staff assumed that DWR would sell excess generation on the spot market.

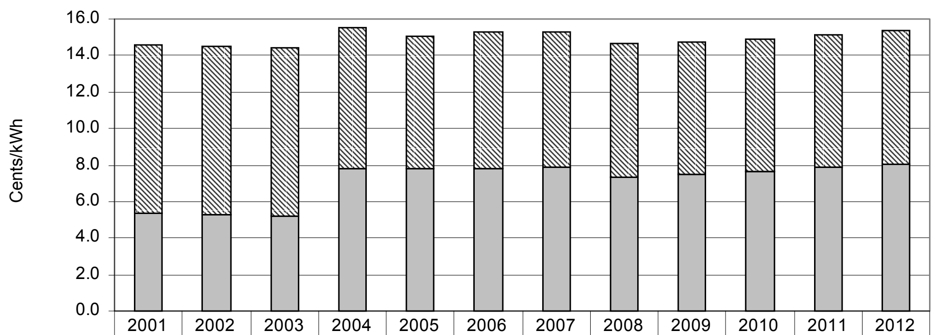
The Commission staff derived utility retained hydro, nuclear and contracts generation costs and volumes from 2001 filings to CPUC dockets, modifying these costs over the forecast period using inflation and cost of natural gas. For example, qualifying facility (QF) costs were split into fixed and variable components. Variable QF costs were adjusted over the forecast period for increases in the cost of natural gas, except for those contracts that were amended to freeze variable contract components for five years. These costs were fixed for five years, and then adjusted for price increases of natural gas beginning in 2006. Although Edison QF contract amendments are now in dispute, Commission staff assumed that the agreements would be honored.

Although Commission staff has access to detailed information on DWR electricity procurement contracts, restrictive nondisclosure provisions prevent using that information in this forecast. Instead and for purposes of the forecast, DWR contract volumes were derived from a benefit-cost analysis of the memorandum of understanding between Edison and Governor Gray Davis prepared by the Blackstone Group L.P. and Saber Partners, LLC in April 2001. To Commission staff's knowledge, this forecast contains DWR contract information that is publicly available. The CPUC determination of DWR contract costs and allocation among the utilities was used, as determined for the years 2001 and 2002 in the Draft CPUC decision in *A.00-11-038 et al*. Costs for the two-year period were assumed to remain constant over the forecast period. DWR electricity costs include a state proposed bond issue to recover general fund purchases incurred to date. Financing was modeled to take place in late 2002 with customer payments beginning in 2003. Bond term and payment information was obtained from the Blackstone/Saber benefit-cost analysis of the MOU between Edison and Governor Gray Davis.

Commission staff used the low reserve margin price scenario for the spot market prices component of generation costs. The low reserve margin price scenario is one of five derived using the Multisym™ model. The other four scenarios: baseline, high reserves margin, lower reserve margin, and lowest reserve margin are described in the **Energy Market Simulations** chapter of this report.

Generation cost represents approximately 7.5 cents/kWh, or 50 percent, of the total rate for most residential customers, but it increases up to 11.0 cents/kWh, or 80 percent for industrial customers, as can be seen in **Figure III-2-2** and **Figure III-2-3**. Although these figures represent Edison's rates, Commission staff observed similar patterns in PG&E's and SDG&E's rates.

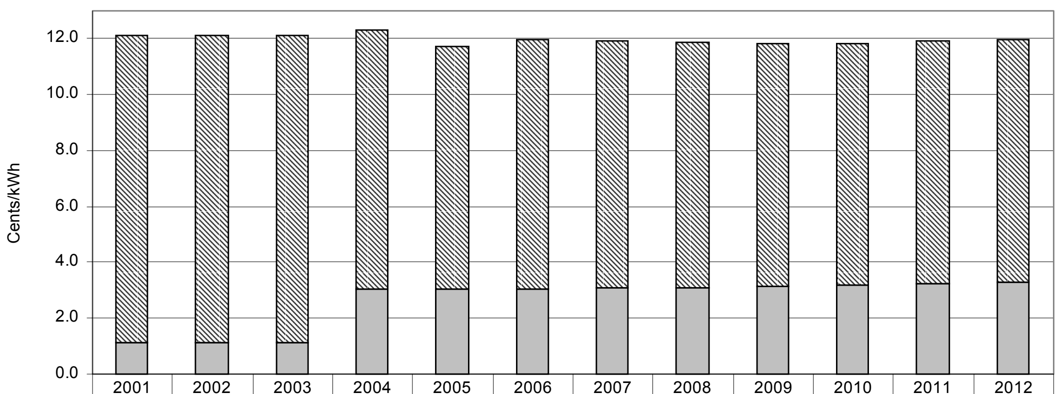
Figure III-2-2
Edison Residential Rate Components ($Nominal)



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Generation	9.2	9.2	9.2	7.7	7.3	7.4	7.4	7.3	7.3	7.2	7.3	7.3
NonGeneration	5.4	5.3	5.2	7.8	7.8	7.8	7.9	7.3	7.5	7.7	7.9	8.1

Source: Energy Commission Staff

Figure III-2-3
Edison Industrial Rate Components ($Nominal)



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Generation	11.0	11.0	11.0	9.3	8.7	8.9	8.8	8.8	8.7	8.6	8.7	8.7
NonGeneration	1.1	1.1	1.1	3.1	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.3

Source: Energy Commission Staff

Non-Generation Costs

Commission staff assumed that tariffed non-generation costs would remain constant through 2003. In addition, the IOUs could file new general rate case applications with the CPUC in 2003, which will become effective in 2004.

The rate doctrine detailed in the CPUC/Edison settlement agreement on the recovery of Edison's debt provides for two types of investment in Edison's infrastructure, which Commission staff assumed to refer to transmission and distribution infrastructure. Consequently, the costs of these authorized investments were divided evenly between transmission and distribution. The first stream is a lump-sum capital investment of $150 million available from a cash residual of tariffed revenues minus actual costs. Commission staff used a break-even analysis to verify adequate residual revenues for these investments and modeled these investments in the years 2002 and 2003. The second stream is a $900 million investment each year for three consecutive years. These costs were modeled using 30-year amortization, taking into account normalized depreciation and a 12.92 percent weighted average pre-tax cost of capital. Increased costs associated with the second stream of investments are not reflected in the rates until 2004.

In regards to public purpose programs and nuclear decommissioning costs, Commission staff assumed that the rates to recover those costs would increase over the forecast period to reflect the rate of inflation.

Non-Recovered Wholesale Electricity Costs

PG&E, Edison and SDG&E incurred substantial debt between 1999 and early 2001 when spot market prices increased, but because the utilities were subject to regulatory and legislative freezes on generation rates, they could not pass along the costs to customers. As a result, PG&E declared bankruptcy in April 2001 and Edison sued the CPUC to fully recover its energy costs from customers. After a series of negotiations, Edison and the CPUC entered into an agreement allowing the utility to recover its debt in its rates. Commission staff also assumed that PG&E and Edison customers would ultimately bear 100 percent of this debt. Its debt would be financed in late 2002 and customer payments on the debt would begin in 2003. Debt amounts modeled were $3.2 billion for PG&E, $2.1 billion for Edison and $750 million for SDG&E. Commission staff assumed the debt would be financed for 15 years at 7.25 percent interest.

Municipal Utilities

For the municipal-utility price outlook, Commission staff first identified current electricity tariffs, energy cost, electricity generation, and purchases of each utility. Subsequently, Commission staff spoke to representatives of each municipal utility to verify current tariffs for typical customers, similar to the IOU customers described above. Once the current parameters were identified, Commission staff used the most recent Energy Commission load, natural gas and electricity spot market price forecast to estimate future energy cost for each utility. Thereafter, future electricity prices were projected using energy cost and inflation estimates.

Several utility financial reports and other information contained in the utilities' websites were used to determine the likelihood of rate increases in the future. For example, the ***2000 Integrated Resource Plan,*** released by LADWP on August 15, 2000, identified two five percent rate decreases, one in 2002 and the other in 2003. However, LADWP staff indicated in recent conversations that they did not foresee a rate decrease or the need for a rate increase during the next ten years. Because of these uncertainties, Commission staff assumed that LADWP would keep rates frozen though 2003 and increase rates thereafter using energy cost and inflation estimates.

SMUD released a ten-year resource plan on October 4, 2001, which identified two 1/4-cent decreases, one in 2002 and the other in 2004. These rate decreases correspond to the temporary rate increases SMUD implemented in May 2001 to compensate for the low hydro production in the 2000-2001 hydro year and to replenish the rate stabilization fund. These rate decreases are reflected in the forecast. After 2004, rates reflect SMUD's expected cost of energy and inflation.

For Burbank, Pasadena, and Glendale, Commission staff assumed that rates would stay frozen through 2003. These three utilities already increased their rates during 2001 to compensate for fuel and energy purchase costs and to replenish their rate stabilization funds. Rates after 2003 reflect anticipated energy cost and inflation.

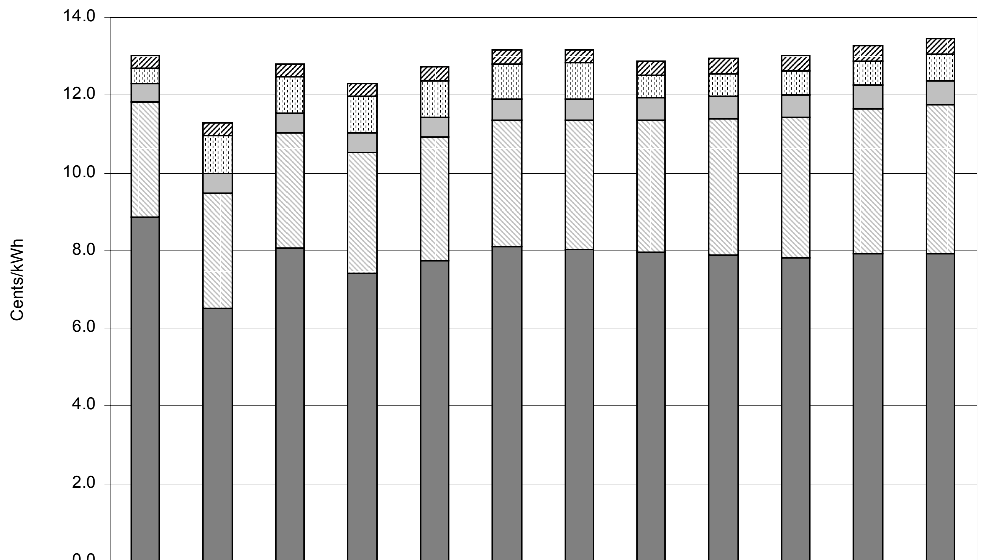
Electricity Rate Components

Retail rates are the prices that consumers pay to electric utilities for electricity used. These rates include the costs for generation of electricity, transmission, distribution, public purpose programs, the competition transition charge (CTC), nuclear decommissioning, ancillary services, and other miscellaneous charges. Electricity rates for municipal utility customers include similar charges.

Figures III-2-4, **III-2-6,** and **III-2-8** provide the approximate charges for generation, transmission, distribution, public purpose programs, and other rate components for PG&E, Edison and SDG&E. Furthermore, **Figures III-2-5**, **III-2-7**, and **III-2-9** provide a breakdown of generation cost components, such as the Department of Water Resources (DWR) contract cost, DWR financing, spot market purchases, utility-owned plants, qualifying facility (QF) contracts, other contracts, and utility debt.

Figure III-2-4 shows the approximate amounts of PG&E's rate components. In 2001, generation cost was close to nine cents per kilowatt hour (kWh). This component declines to 6.5 cents/kWh next year, but it increases consistently to approximately 8.0 cents/kWh for the rest of the forecast period. Overall, the generation component is approximately 60 percent of the total electricity rate.

Figure III-2-4
PG&E Electricity Rate Components ($Nominal)

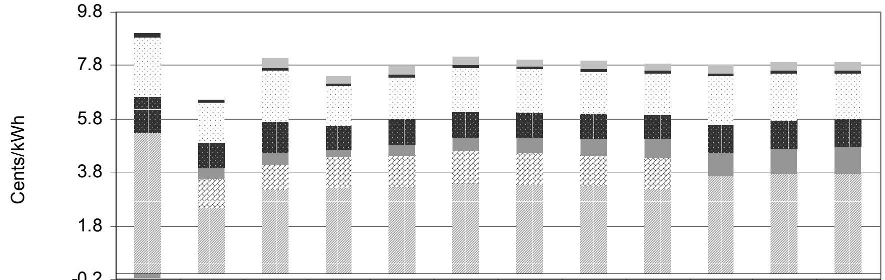


	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Public Purpose	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Other	0.4	1.0	1.0	1.0	0.9	0.9	0.9	0.6	0.6	0.6	0.6	0.7
Transmission	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Distribution	3.0	3.0	3.0	3.1	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.8
Generation	8.9	6.5	8.1	7.4	7.7	8.1	8.0	8.0	7.9	7.8	7.9	7.9

Source: California Energy Commission Staff

DWR energy contract cost currently amounts to approximately 5.3 cents/kWh, or 60 percent of PG&E's generation cost component. However, DWR contract cost could decrease to less than 3.0 cents/kWh in 2002 and 2003, but would increase slightly up to 3.7 cents/kWh by 2012. The QF contract cost portion of the generation cost component, on the other hand, varies between 1.5 and 2.0 cents/kWh. The spot market purchases cost fluctuates between 0.4 and 1.0 cents/kWh, as indicated in **Figure III-2-5**.

Figure III-2-5 PG&E
Generation Cost Components ($Nominal)



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Utility Debt	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Other Utility Contracts	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Utility QF Contracts	2.3	1.6	1.9	1.5	1.6	1.7	1.6	1.6	1.6	1.8	1.8	1.7
Utility Plants	1.4	0.9	1.1	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Spot Market	-0.1	0.4	0.5	0.3	0.4	0.5	0.6	0.6	0.7	0.9	1.0	1.0
DWR Financing	0.0	1.1	0.9	1.1	1.2	1.2	1.2	1.2	1.1	0.0	0.0	0.0
DWR Contract	5.3	2.5	3.1	3.2	3.2	3.4	3.3	3.3	3.2	3.6	3.8	3.8

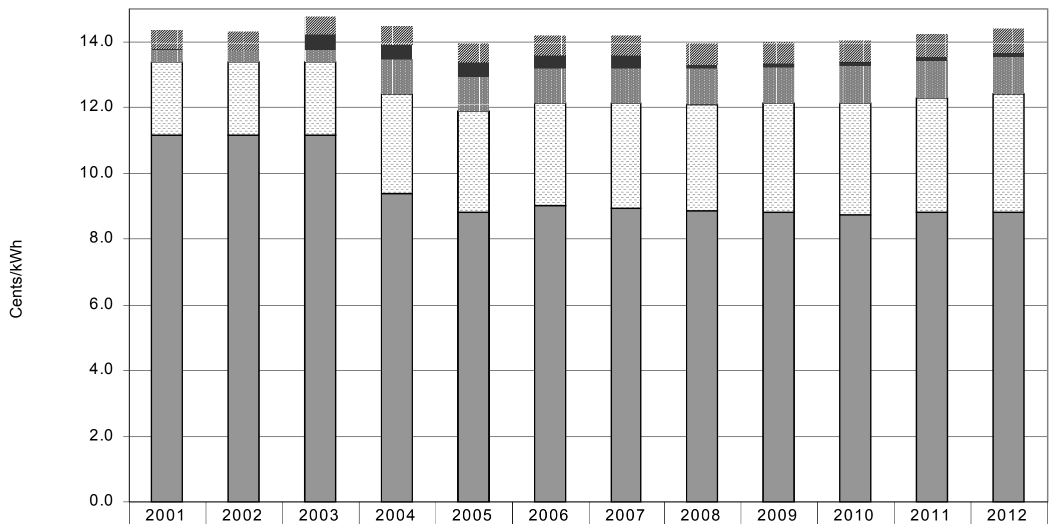
Source: California Energy Commission Staff

Figure III-2-6 shows that the generation cost component of Edison rates declines from approximately 11.0 cents/kWh, or 80 percent of the total rate, today to 8.8 cents/kWh, or 60 percent, by 2012. The distribution cost component, on the other hand, increases from 2.2 cents/kWh today to approximately 3.6 cents/kWh in 2012.

In contrast to PG&E, the DWR contract cost portion of Edison's generation costs is less than 3.0 cents/kWh, or 30 percent of the total rate. However, QF contract costs of generation amount to more than 4.7 cents/kWh today and could decrease to approximately 4.0 cents/kWh by 2004. Spot market purchase costs decline from 2.0 cents/kWh today to less than 1.0 cents/kWh in 2002. However, spot market purchases could increase up to 1.4 cents/kWh by 2012, as shown in **Figure III-2-7**.

Figure III-2-8 shows that the generation cost component of SDG&E rates amounts to approximately 8.0 cents/kWh. The distribution cost component, on the other hand, increases from 3.0 cents/kWh today to approximately 4.0 cents/kWh by 2012.

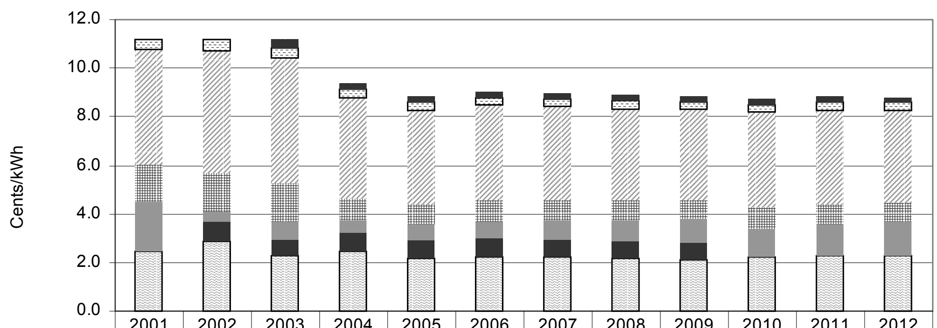
Figure III-2-6
Edison Electricity Rate Components ($Nominal)



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Public Purpose	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Other	0.04	0.01	0.5	0.4	0.4	0.4	0.4	0.1	0.1	0.1	0.1	0.1
Transmission	0.4	0.4	0.4	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2
Distribution	2.2	2.2	2.2	3.0	3.1	3.1	3.2	3.2	3.3	3.4	3.5	3.6
Generation	11.2	11.2	11.2	9.4	8.8	9.0	8.9	8.9	8.8	8.8	8.8	8.8

Source: Energy Commission Staff

Figure III-2-7
Edison Generation Cost Components ($Nominal)

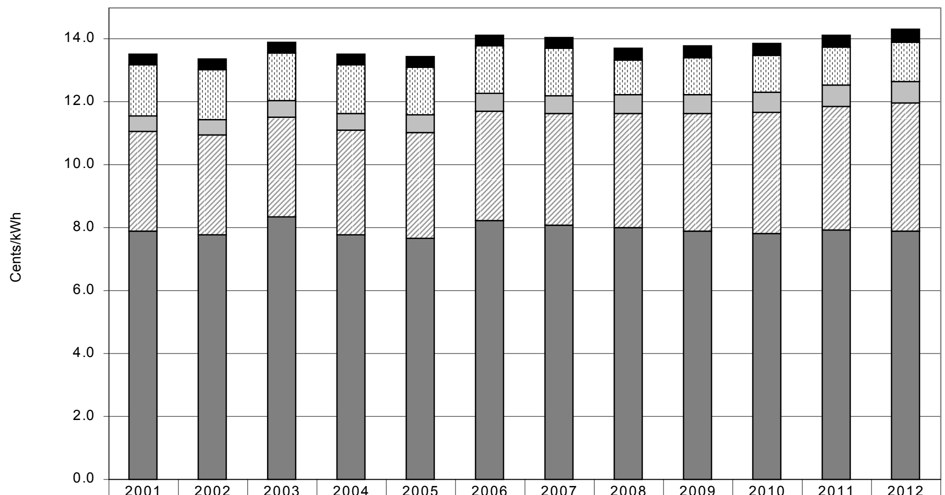


	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Utility Debt	0.0	0.0	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other Utility Contracts	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Utility QF Contracts	4.7	5.0	5.1	4.2	3.9	3.9	3.9	3.8	3.7	3.9	3.9	3.8
Utility Plants	1.5	1.6	1.6	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Spot Market	2.1	0.4	0.7	0.5	0.6	0.7	0.8	0.9	1.0	1.2	1.3	1.4
DWR Financing	0.0	0.8	0.6	0.8	0.7	0.7	0.7	0.7	0.7	0.0	0.0	0.0
DWR Contract	2.4	2.9	2.3	2.5	2.2	2.2	2.2	2.2	2.1	2.2	2.3	2.3

Source: Energy Commission Staff

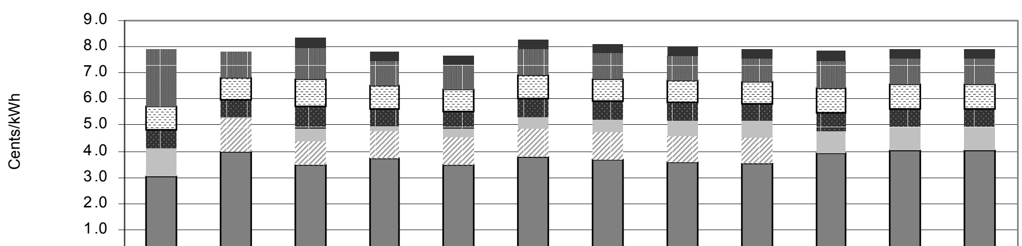
The DWR contract cost portion of SDG&E generation costs increases from 3.0 cents/kWh today to approximately 4.0 cents/kWh by 2012. However, spot market purchase costs decline drastically from 1.0 cents/kWh today to less than 0.5 cents/kWh over the next five years. Thereafter, spot market purchase costs could increase above 0.5 cents/kWh by 2012, as shown in **Figure III-2-9**.

Figure III-2-8
SDG&E Electricity Rate Components ($Nominal)



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Public Purpose	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.1	1.1	1.2	1.2	1.2
Transmission	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Distribution	3.2	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.7	3.8	4.0	4.1
Generation	7.9	7.8	8.4	7.8	7.7	8.3	8.1	8.0	7.9	7.8	7.9	7.9

Figure III-2-9
SDG&E Generation Cost Components ($Nominal)



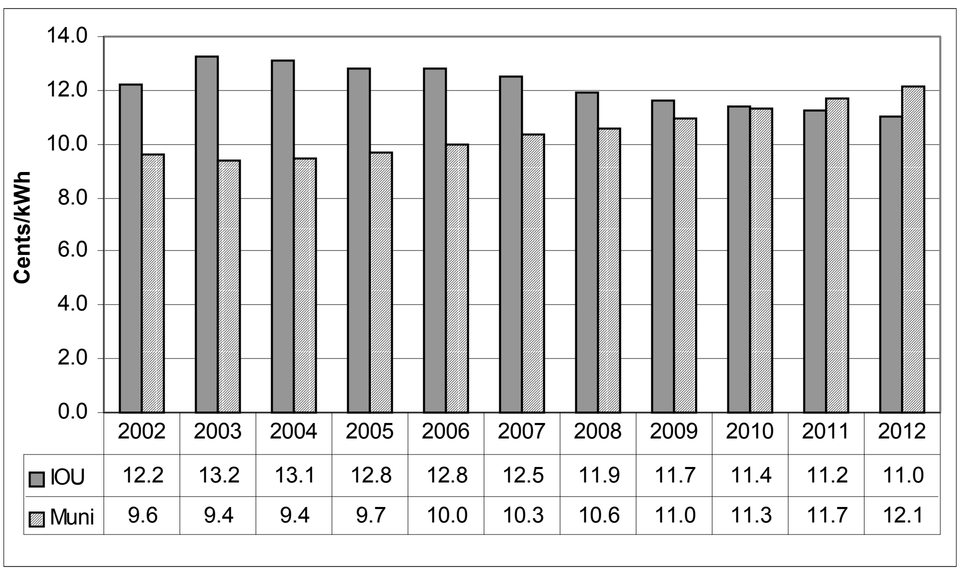
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Utility Debt	0.0	0.0	0.4	0.3	0.3	0.4	0.3	0.3	0.3	0.4	0.4	0.4
Other Utility Contracts	2.2	1.0	1.2	0.9	0.9	1.0	1.0	0.9	0.9	1.0	1.0	1.0
Utility QF Contracts	0.9	0.9	1.1	0.9	0.9	0.9	0.9	0.9	0.9	1.0	0.9	0.9
Utility Plants	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.6	0.7	0.7	0.7
Spot Market	1.1	0.0	0.5	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	0.9
DWR Financing	0.0	1.3	0.9	1.0	1.0	1.1	1.0	1.0	1.0	0.0	0.0	0.0
DWR Contract	3.0	4.0	3.5	3.7	3.5	3.8	3.7	3.6	3.5	3.9	4.0	4.0

Source: Energy Commission Staff

Rate Outlook 2002-2012

A comparison of utility average electricity rates in **Figure III-2-10** shows that (real $2001) rates for IOU customers are generally higher than rates for municipal utility customers in the initial years, but even out in the later years. If the State Legislature or regulators decide that ratepayers should bear the IOUs' debt, rates would likely increase gradually up to an average of 13.0 cents/kWh in the 2002-2005 period. However, if FERC orders refunds to state utilities for alleged overcharges by merchant generators and energy traders late last year and early this year and the refunds are distributed to ratepayers, then the rates would likely decline. Once the debt is recovered, rates could decline for the rest of the forecast period, as indicated in **Figure III-2-10**. Municipal rates, on the other hand, would remain constant for the next few years, but would most likely increase in the later years to reflect higher energy costs and inflation.

Figure III-2-10
IOU/Muni System Electricity Rates ($2001)



Source: Energy Commission Staff

Table III-2-3 shows system average electricity rates in real $2001 for IOUs and municipal utilities for the 2002-2012 period.

Table III-2-3
System Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	10.48	13.75	13.16	9.58	8.92	11.77	11.68	11.78	103.02
2003	12.41	14.02	13.47	9.36	8.71	11.50	11.41	11.51	105.46
2004	11.75	14.51	12.90	9.63	8.26	11.94	11.72	11.83	108.28
2005	11.91	13.72	12.59	9.93	8.47	12.28	12.07	12.18	111.22
2006	12.04	13.63	12.92	10.23	8.75	12.57	12.41	12.52	113.99
2007	11.77	13.26	12.56	10.53	9.05	12.77	12.76	12.88	116.91
2008	11.19	12.70	11.92	10.82	9.32	12.97	13.09	13.21	119.62
2009	10.94	12.39	11.65	11.21	9.65	13.18	13.55	13.67	123.65
2010	10.68	12.10	11.40	11.58	10.04	13.41	13.99	14.12	127.44
2011	10.58	11.90	11.26	11.98	10.43	13.57	13.86	14.59	131.45
2012	10.37	11.64	11.04	12.41	10.86	13.73	13.72	15.09	135.70

Source: Energy Commission Staff

Differences in rates between IOU and municipal residential customers show similar patterns to average utility rates. Although rates for PG&E, Edison, and SDG&E residential customers could reach approximately 12.0, 15.0, and 13.0 cents/kWh respectively in 2004, rates for LADWP, SMUD and the other municipal residential customers would be approximately 10.0, 8.0, 13.0 cents/kWh, as shown in **Table III-2-4**.

Table III-2-4
Residential Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	9.94	13.00	13.53	10.13	8.73	12.32	12.56	13.61	103.02
2003	12.10	13.99	13.35	9.89	8.53	12.03	12.27	13.29	105.46
2004	11.58	14.81	13.16	10.18	8.08	12.49	12.61	13.66	108.28
2005	11.67	14.10	12.86	10.49	8.29	12.85	12.98	14.07	111.22
2006	11.74	13.96	13.09	10.80	8.56	13.16	13.34	14.46	113.99
2007	11.49	13.62	12.73	11.13	8.86	13.36	13.72	14.87	116.91
2008	10.67	12.73	11.79	11.44	9.12	13.57	14.08	15.26	119.62
2009	10.48	12.47	11.57	11.85	9.45	13.80	14.57	15.79	123.65
2010	10.28	12.22	11.36	12.25	9.83	14.03	15.04	16.31	127.44
2011	10.20	12.06	11.25	12.67	10.22	14.20	14.90	16.85	131.45
2012	10.03	11.83	11.07	13.12	10.64	14.37	14.75	17.43	135.70

Source: Energy Commission Staff

Table III-2-5 shows that electricity rates for Edison small commercial customers could reach over 19.0 cents/kWh in 2003, compared to 10.5, 12.0, 13.0, and 15.0 cents/kWh for municipal utility customers located in Southern California. However, our projection illustrates that IOU rates would decline and municipal rates would increase over the entire outlook period. Consequently, municipal rates could be higher than IOU rates for some utility customers in 2006. The exceptions are LADWP and SMUD rates, which are lower than any other rates.

Table III-2-5
Small Commercial Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	13.56	18.69	16.95	10.52	9.95	12.19	13.07	15.58	103.02
2003	16.51	19.54	17.55	10.28	9.72	11.90	12.77	15.21	105.46
2004	15.62	18.11	16.57	10.57	9.24	12.36	13.12	15.64	108.28
2005	15.79	17.15	16.15	10.90	9.48	12.72	13.51	16.10	111.22
2006	15.94	17.03	16.51	11.23	9.79	13.02	13.89	16.55	113.99
2007	15.57	16.58	16.00	11.56	10.13	13.22	14.28	17.02	116.91
2008	14.60	15.48	14.89	11.88	10.43	13.43	14.65	17.47	119.62
2009	14.29	15.14	14.55	12.31	10.81	13.65	15.16	18.08	123.65
2010	13.96	14.80	14.23	12.72	11.24	13.88	15.66	18.67	127.44
2011	13.83	14.59	14.05	13.16	11.68	14.05	15.51	19.29	131.45
2012	13.56	14.29	13.76	13.63	12.16	14.21	15.35	19.95	135.70

Source: Energy Commission Staff

Table III-2-6 shows electricity rates for IOU medium commercial customers. The rates fluctuate between 11.0 and 15.0 cents/kWh for the IOUs and 8.0 and 11.0 cents/kWh for LADWP and SMUD. Rates for Burbank, Pasadena and Glendale are closer to Edison's rates.

IOU industrial electricity rates fluctuate between 9.0 and 11.0 cents/kWh. Rates for PG&E and SMUD customers seem closer than rates for Edison and LADWP's rates, as indicated in **Table III-2-7**.

Table III-2-6
Medium Commercial Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	11.25	14.79	12.47	9.29	9.00	12.78	12.55	13.43	103.02
2003	12.77	14.57	13.11	9.08	8.79	12.48	12.26	13.12	105.46
2004	12.03	15.69	12.33	9.34	8.33	12.96	12.59	13.49	108.28
2005	12.24	14.82	12.05	9.63	8.56	13.34	12.97	13.89	111.22
2006	12.43	14.71	12.46	9.91	8.83	13.65	13.33	14.28	113.99
2007	12.16	14.27	12.11	10.21	9.14	13.87	13.71	14.68	116.91
2008	11.87	13.92	11.82	10.49	9.42	14.08	14.07	15.07	119.62
2009	11.60	13.58	11.54	10.87	9.75	14.32	14.56	15.59	123.65
2010	11.32	13.23	11.27	11.24	10.15	14.56	15.03	16.10	127.44
2011	11.20	13.01	11.13	11.62	10.54	14.73	14.89	16.64	131.45
2012	10.97	12.71	10.90	12.04	10.98	14.91	14.74	17.21	135.70

Source: Energy Commission Staff

Table III-2-7
Medium Industrial Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	7.65	11.93	10.13	7.20	7.64	11.19	11.05	7.92	103.02
2003	8.97	11.75	10.79	7.04	7.46	10.93	10.80	7.73	105.46
2004	8.28	11.72	9.95	7.24	7.03	11.35	11.10	7.95	108.28
2005	8.45	10.98	9.67	7.46	7.22	11.68	11.43	8.18	111.22
2006	8.62	10.92	10.08	7.68	7.45	11.96	11.75	8.41	113.99
2007	8.39	10.61	9.73	7.91	7.72	12.15	12.08	8.65	116.91
2008	8.14	10.30	9.44	8.13	7.95	12.33	12.39	8.88	119.62
2009	7.91	10.00	9.16	8.42	8.23	12.54	12.82	9.19	123.65
2010	7.67	9.70	8.90	8.71	8.56	12.75	13.24	9.49	127.44
2011	7.57	9.50	8.76	9.01	8.90	12.90	13.12	9.80	131.45
2012	7.37	9.24	8.53	9.33	9.26	13.06	12.98	10.14	135.70

Source: Energy Commission Staff

Table III-2-8 shows that the IOU electricity rate for agricultural customers fluctuates between 11.0 and 14.0 cents/kWh. However, SMUD shows significantly lower rates than PG&E.

Table III-2-8
Agricultural Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	12.92	13.00	12.41	N/A	9.03	N/A	N/A	N/A	103.02
2003	14.48	12.80	12.87	N/A	8.82	N/A	N/A	N/A	105.46
2004	13.75	12.99	12.34	N/A	8.59	N/A	N/A	N/A	108.28
2005	13.96	12.29	12.12	N/A	8.82	N/A	N/A	N/A	111.22
2006	14.17	12.24	12.44	N/A	9.10	N/A	N/A	N/A	113.99
2007	13.88	11.96	12.16	N/A	9.42	N/A	N/A	N/A	116.91
2008	13.58	11.67	11.94	N/A	9.70	N/A	N/A	N/A	119.62
2009	13.30	11.40	11.72	N/A	10.05	N/A	N/A	N/A	123.65
2010	13.01	11.13	11.51	N/A	10.46	N/A	N/A	N/A	127.44
2011	12.89	10.95	11.40	N/A	10.86	N/A	N/A	N/A	131.45
2012	12.65	10.71	11.22	N/A	11.31	N/A	N/A	N/A	135.70

Source: Energy Commission Staff

Conclusions

Based on this analysis, the Commission concludes that:

1. Future retail electricity rates for the IOUs depend to a certain extent on the regulatory decisions of the FERC, the State Legislature, the Governor, and the CPUC, rather than the spot market prices. Because municipal utilities have long-term contracts for energy, their rates depend more directly on the price of natural gas and to some extent the need to replenish their rate stabilization funds

2. Most of the IOU electricity rate components are relatively set for the next ten years. Therefore, major rate fluctuations are unlikely.

3. The energy generation cost reflected in the rates of residential customers of PG&E, Edison, and SDG&E amount to approximately 50 percent of the total electricity rate. However, for medium commercial and industrial customers, they can account for up to 80 percent of the rate.

4. If ratepayers bear the cost of the debt incurred by the IOUs in 2000 and 2001, electricity rates would increase for each utility in the 2002-2005 period, as indicated in this outlook. Rate decreases are likely in the following years. Municipal utilities will most likely keep their rates constant for the 2002-2003 period, but would increase then in the following years.

5. Average electricity rates for IOU small commercial customers could reach up to 19 cents/kWh in 2003.

6. Because of their previous long-term power contracts, municipal utilities were able to endure the high energy costs of late 2000 and early 2001. Rates for municipal customers would stay lower than rates for IOU customers, at least for another eight years. LADWP is in a good position to keep its rates lower than Edison does. If SMUD is successful in diversifying its resources, the utility could also keep its rates lower than PG&E for the next six to seven years.

Chapter III-3 Developing Demand Responsive Loads

Overview

California faces several options in its efforts to ensure a balance between supply and demand. Traditionally, loads are served by generating facilities. However, because California's electric peak demand is almost completely caused by summer-time air conditioning loads that show sharp peaks, reductions in demand due to market pricing tariffs or demand responsiveness programs may be effective in balancing supply and demand. Substantial monetary, environmental and system performance benefits may result from using demand responsiveness to ensure California's electricity system remains reliable.

Demand response can come from real-time price (RTP) tariffs on dispatchable load curtailment programs that enable end-users to respond to market prices or adverse system conditions reducing loads, respectively. Customers on RTP can save money by reducing consumption in high priced periods or by shifting loads from high to low price periods. Customers on load curtailment programs respond to incentives to reduce loads when system conditions trigger load curtailment program operation. Both forms of demand responsiveness reduce loads when market prices and/or system conditions warrant this action.

Chapter III-1 of this report noted that the wholesale and retail market structures are interdependent. Effective generation price signals cannot take place independent of the retail market. Consumers must choose to consume or not consume based on prices that reflect market conditions. They may make this choice directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability. Further, in assessing the tradeoffs between demand response and peaking generators, the Commission believes that large amounts of demand responsive loads can be acquired that are cheaper than peaking generators. This chapter assesses different types of demand responsive options and recommends pursuit of an aggregate capability of 2,500 MW through new and/or revised program designs.

Six Criteria

Integrated planning trade-offs are necessary to ensure a balance between supply and demand. Determining the mix among various options requires a close analysis of their characteristics compared to realistic evaluation criteria. Further, power cannot be assured under every possible circumstance at a cost that consumers are willing to pay. The cost of serving load is increasingly expensive as increasingly unlikely contingencies are mitigated. System planners have to consider balancing reliability and cost.

This section describes six criteria we believe are appropriate in making these tradeoffs, whether the options are peakers versus demand response or within demand response RTP tariffs versus load control programs. The six criteria are: economic efficiency, reducing exposure to price spikes, planning uncertainty, operating uncertainty, flexibility, and secondary consequences through feedback into the rest of the market.

<u>Economic efficiency</u> cannot be obtained if consumers are required to purchase unnecessary or unwanted products. Traditional reliability measures such as loss of load probability or expected unserved energy assume that all consumers want the same level of reliability. In fact, some consumers are willing to forego consumption when electricity is costly. All modern value of service studies reveal considerable diversity among end-users about their willingness to pay for electricity-service options. By not taking into account the willingness of some consumers to reduce consumption during costly periods, planning paradigms fail to make use of a potential resource. Comparison of resources using this criteria would concentrate on the costs and benefits of generation and demand-side resources to the participants and to the market as a whole.

<u>Reducing exposure to price spikes</u> means reducing average prices because the peak price is lowered more than the off-peak price is raised. Reducing exposure to excessive prices admits that an occasional dose of high prices in the right circumstances might be the most cost-effective way to balance net electricity demand with generation.

<u>Planning uncertainty</u> describes the problem of translating analytic options into operation. Power plants can be difficult to license and build. On the other hand, because they are developed by identifiable owners with clear property rights and profit motivations, they are relatively straightforward to contract and finance. Demand responsive programs can have marketing and recruitment problems that compromise their load reduction capability. In making trade-offs, we need to account for the feasibility of a preferred solution delivering all its benefits and articulate the costs of being wrong.

<u>Operating uncertainty</u> describes the problem of actually achieving generation when peakers are called upon or reducing load when demand responsive programs are triggered into operation. If financial incentives are in place, new peaking powerplants are dependable. When called upon, they generally start. Demand responsive programs possess irreducible performance uncertainties. When called upon, program participants have a choice about how much load they will actually deliver. Clear rewards and penalties, probabilistic

approaches and experience can narrow the range of uncertainty, but cannot eliminate it.

Flexibility describes the ability of the option to be adaptable under changing circumstances. Expectations of rapid economic growth may suggest supply-demand imbalances that require near-term solutions. Peakers require financial commitments of five or more years. Demand responsive programs typically involve obligations of one to three years. If a recession slows load growth, demand response can be more flexible in adapting to new conditions than can peakers.

Secondary consequences describe positive and negative impacts if the option supports or detracts from other valuable market features. A demand response program benefit is that experience in adjusting demand in peak periods encourages innovation in off-peak periods as well. Rather than just cutting load, consumers may find benefit in shifting loads to off-peak periods. This additional flattening of the load curve makes new generation less risky to developers. A secondary benefit through an addition of a peaker might be that a local area needs nearby generation to improve local grid reliability. A secondary cost is the concern that desirable generation sites are limited; maybe sites are better used for the best long-term resources, not for short duration projects.

Comparing Characteristics of Demand Response Options

The previous section identified and discussed six criteria that should be used in comparing the characteristics of any resource options. This section will use these criteria to compare two alternative types of demand responsiveness – load curtailment programs and RTP tariffs.

Economic Efficiency Through Consumer Choice

All modern value of service studies reveal considerable diversity among end-users about their willingness to pay for electricity service. Further, within an individual end-user's mix of end-uses, there is even greater diversity about the value of ensuring unrestricted power for specific end-uses. Consumer acceptance of RTP tariffs is poorly understood, since some of the consumer research directed by the legislature has not yet been conducted.[1] Unfortunately, there is as yet no reliability planning paradigm that accounts for the willingness of consumers to forego some electricity usage when prices are high, despite clear evidence that this is quite acceptable to many end-users.

Demand responsiveness in the form of load curtailment programs permits at least some end-users to forego some electricity use when the economic incentive is high enough. The use of load curtailment programs in December 2000 to May 2001 saved California from rotating outages on numerous instances. In substantial measure these participants provided the balancing factor that matched essential loads with supply. Using generating resources to satisfy loads provides no signal to elicit load reductions from those whose values for electricity are less than its cost of supply.

Load reductions resulting from load curtailment programs achieve these benefits differently than do RTP tariffs. Load curtailment programs tend to put end-users into specific frameworks that have preannounced incentive mechanisms. RTP tariffs expose end-users to the myriad of actual wholesale price patterns. In general RTP tariffs would perform better than load curtailment programs in achieving economic efficiency.

Reducing Exposure to Excessive Market Prices

The experiences of May 2000 through May 2001 reveal the potential problems of dysfunctional electricity markets. Excessive prices were being demanded in the marketplace and drastic consequences have resulted. Not the least of which is an abhorrence of markets themselves among some decision-makers.

Reducing exposure to excessive market prices is likely to be more cost-effective through time than avoiding markets entirely by relying upon command and control decision-making. The failings of command and control decision-making and its high costs were precisely what motivated many to promote greater reliance upon markets in the first place. Reducing exposure is not the same as eliminating exposure. Reducing exposure to excessive prices admits that an occasional dose of high prices in the right circumstances might be the most cost-effective way to satisfy net electricity demand with generation.

Most load curtailment programs are designed to reduce load in times of physical shortage, such as at the hour of system peak or that can also occur during transmission contingencies. RTP tariffs, in contrast, provide a wholesale market price signal continuously to RTP participants, thus inducing load reductions (or load additions) whenever participants find value to be less than cost (value greater than cost).

Some new demand bidding programs are designed to allow demand responsive programs to compete directly with generators in a bidding framework. The short-term focus of such programs means they operate in a forward time horizon of a few hours to a few days. Longer term energy imbalances must be addressed through energy-oriented measures, such as more baseload generation, additional import capability through transmission line expansions, or energy efficiency measures. Nonetheless, by flattening the load curve (reducing peaks when prices are high, and filling valleys when prices are low), RTP tariffs can make the system operate more efficiently.

Several studies have examined the impact increased demand response would have on market performance, especially the level of market clearing prices. Such studies generally find increased demand responsiveness would reduce market-clearing prices, and therefore recommend policies to increase demand responsiveness through tariffs and load curtailment programs. A recent study estimated that having an increased level of demand responsiveness in place could have saved California $2.5 Billion in year 2000.[2]

Planning Uncertainty

Planning uncertainty describes the problem of translating analytic options into operational programs. Demand responsive programs and tariffs can be designed, but unexpected marketing and recruitment problems may leave load reduction capability at a level lower than planned and budgeted for. It is unclear whether load curtailment programs or RTP tariffs have greater planning uncertainty as a general rule, but experience during 2001 suggests that load curtailment programs are currently more acceptable to decision-makers in California than are RTP tariffs.[3] Only more detailed and explicit consumer research can ascertain what level of RTP and/or load control program participation can be obtained.

Operating Uncertainty

Operating uncertainty describes the problem of actually achieving load reductions when the programs are triggered into operation. Without operating experience, load curtailment programs are commonly considered to be more reliable than RTP tariffs. When load curtailment programs are triggered they generally respond. RTP tariffs possess greater performance uncertainties at the planning stage. When called upon, how much load will RTP tariff participants actually deliver this time? Experience can justify narrowing the range of uncertainty, but cannot eliminate it.

Georgia Power (GP) has operated a real-time pricing (RTP) tariff for a decade. They now know that of the 850 MW of participant load shedding capability, they can count upon so many MW of load reduction at each RTP price level. They may get more if business conditions and numerous other factors are favorable to load reductions. Over time, their experience in operating the RTP tariff has narrowed the uncertainty of the program's performance to the point that GP now relies upon 500 MW of "supply" in its resource planning process.

Flexibility

Flexibility describes the ability of the option to be adaptable under changing circumstances. Expectations of rapid economic growth may suggest supply-demand imbalances that require near term solutions. It is clear that peakers require long term financial commitments, ten years or more, to bring their costs down to the range of demand responsive options. Demand responsive programs typically involve obligations of one to three years. If a recession slows load growth, demand responsive can be more flexible in adapting to new conditions than can peakers under long term contracts. Load curtailment programs are much more rigid than are RTP tariffs in conforming to evolving and constantly changing wholesale market conditions. However, from the perspective of the participant, the clearly established criteria of load curtailment programs may be more welcome than the need for constant monitoring explicit in RTP tariffs.

Corollary Benefits/Costs

Corollary benefits/costs describes the potential for positive and negative consequences if the option supports or detracts from other valuable characteristics. An example of a benefit is that demand responsive programs with RTP metering systems introduce interval data to end-users and increase the chance that RTP tariffs will be found acceptable. A voluntary RTP tariff, as proposed by the Energy Commission to CPUC during 2001, would develop end-user familiarity with the concept, and thus reduce perceived burdens in shifting to mandatory RTP tariffs.

Comparing Load Curtailment Programs versus RTP Tariffs

Table III-3-1 uses the criteria established in Chapter III-1, and discussed above, to compare load curtailment programs versus RTP tariffs. In general RTP programs have greater theoretical benefits, but planning uncertainty is very large given regulatory decision-making experience in California in year 2001.

Issues For Demand Responsiveness

The generating capacity problems of late 2000 and early 2001 induced the ISO and UDCs to repeatedly call for interruptible load curtailments, exhausting the annual limits for PG&E participants and nearly exhausting the annual limits for SCE participants. The outcry from these commercial and industrial customers about the unprecedented level of outages revealed substantial problems with these programs. Pre-specified limits that utilities expect to be available are grossly higher than participant expectations. As a result, numerous program participants and agency personnel are now much more oriented to pay-for-performance program designs in which participants elect to reduce load voluntarily. Each participant has to weigh the benefits of the incentive payment versus the costs of the lost production that a curtailment would induce.

Table III-3-1
Using Comparison Criteria to Contrast Load Curtailment Programs versus RTP Tariffs

Criteria	Demand Responsive Capability	RTP Tariffs
Economic Efficiency	Can reduce customer costs of outages	Optimizes efficiency by fostering individual end-user value of service orientation
Reducing Market Prices	Some load curtailment programs could also reduce market clearing prices	RTP programs would be more effective in reducing market-clearing prices in conditions prior to reserve difficulties
Planning Uncertainty	Existing CPUC funding mechanisms create uncertainty about what marketing efforts will match goals for program load reduction capability	CPUC has been extremely reluctant to adopt any RTP tariff design, apparently fearing the legitimacy of the market prices themselves
Operating Uncertainty	New demand responsive programs have uncertainties about extent to which load reductions will actually occur; some load curtailment capability is constrained to operate only during summer air conditioning season	Lack of experience with RTP in California means that it is inherently more uncertain in the beginning as RTP participants determine how to respond
Flexibility	Demand responsive programs require 1-3 year commitments to recover capital costs	RTP is more flexible by operating continuously, year round and without explicit program constraints
Corollary Benefits/Costs	Pursuing load curtailment programs can be a transitional step leading to RTP rates in the future	Voluntary RTP tariffs can be a precursor to mandatory RTP tariffs for classes of end-user

This section examines the issues associated with reliance upon demand responsiveness as a means to equilibrate supply and demand. These issues include:

- Need for load curtailment programs versus reliance upon end-user response to market prices.
- Design of load curtailment programs.
- Cost of load curtailment programs.
- Potential customer interest in load curtailment programs.
- Coordination of funding and program authorization among agencies.

Need for Load Curtailment Programs

Load curtailment programs are non-rate, DSM-like programs that collect, equip and dispatch specific end-user loads when “triggers” such as low operating reserves or other system conditions are encountered. Real-time pricing is an example of a tariff that produces load reductions, assuming market prices are signaled to participants in the tariff, comparable to load curtailment program results. In the ideal world, there is no need for explicit load curtailment programs separate from such tariffs. Energy tariffs for end-users would provide a market price signal, and end-users would moderate demand in response to prices. Modern electronic communication and control technologies allows this concept to be implemented in the real world. The principal rationale for load curtailment programs is the absence of a rate structure that communicates market prices to end-users, thus inhibiting them from making their own load control decisions in a framework of cost versus individual value, or sufficient experience with such tariff-response to be willing to rely upon it. Since the legislative and regulatory response to the market crisis has been to defer reliance upon market-based solutions until the overall market is redesigned, we must expect to continue to need load curtailment programs until this fundamental problem is overcome. At least for 2002, a mix of load curtailment programs is likely to continue to be required, but this may not be true for the long run.

Design of Demand Responsive Programs and Tariffs

The past year has revealed whole new contingencies that were never considered in traditional system planning**.** Financial meltdown of utilities and inability to pay producers was not a threat that was guarded against**.** It is clear that demand responsive programs and tariffs as they were designed and marketed to participants in 1990's were ill suited for repeated use under these conditions.

The Energy Commission believes that it is essential to establish the purpose(s) of demand responsive programs and tariffs prior to the design of load curtailment programs and RTP tariffs. Possible purposes include:

- Shave peak load to ensure system reliability when resources are stressed and no end-users respond to market prices.

- Remove load in selected regions when transmission contingencies occur and the alternative is rolling blackouts as occurred for certain Bay Area customers of PG&E on June 14, 2000.

- Reduce costs of procuring energy for bundled service customers who do not otherwise face market rates for power purchases.

- Build load and shed load depending upon the short-term and long-term needs of the system.

- Encourage more balance across hourly and seasonal loads to facilitate greater efficiency in both generation and consumption.

For the purpose of comparing demand responsive programs and methods with peakers, only the first two of these possible purposes should be considered. This is important because the purpose for the program may dictate its design and render it ill-suited to other purposes. For example, a load curtailment program designed as emergency curtailment under ISO Stage 2 emergencies is not well suited to moderating market prices. However, RTP tariffs might be able to provide acceptable responses to more than one purpose.

Cost of Load Curtailment Programs

There are several cost elements characterizing most load curtailment programs. Some of these are also common to real-time pricing tariffs. These are:

- Program design, systems development and regulatory approval.
- Marketing and recruitment of participants.
- End-use customer equipment.
- Ongoing program operating costs (program operator and participating end-user).
- Incentive payments to participants.

The first three are largely, although perhaps not exclusively, up front, one-time only costs. The latter two are ongoing costs. Depending upon the design of the load curtailment program, these may be relatively fixed and independent of performance, or they may be highly variable tied directly to program performance.

This report cannot provide detailed assessments of costs for specific programs, but **Table III-3-2** indicates the relative costs of various program types (from the perspective of the funding authority). **Table III-3-2** shows that there are tradeoffs. Load curtailment programs with reservation payments can be very expensive per kW load reduced if they are not used much. RTP used only in a curtailment-motivation pattern could be costly under these same conditions. Alternatively, pay-for-performance programs like RTP rates increase in their costs if reliability payments are designed to induce load reductions when system conditions are stressed. **Figure III-3-1** compares costs of performance as hours of performance decline, showing that various alternatives can have similar cost curves. RTP would likely fall below the costs of high reservation payment programs.

Examined from the perspective of the participant, programs that have high fixed costs and low variable costs tend to be desirable if they are used little, since the fixed payments more than offset operating inconveniences and loss of production. Used more, high fixed cost programs become undesirable from the customer perspective since using them means normal electricity usage and its attendent productive activities are disrupted. RTP on the other hand, requires no fixed set of curtailment events, so presumably the participating customers reduce only those loads where the monetary incentive exceeds the value of the lost production, and increase loads when the value of the greater production exceeds overall production costs.

Table III-3-2
Relative Costs of Key Elements by Program Type

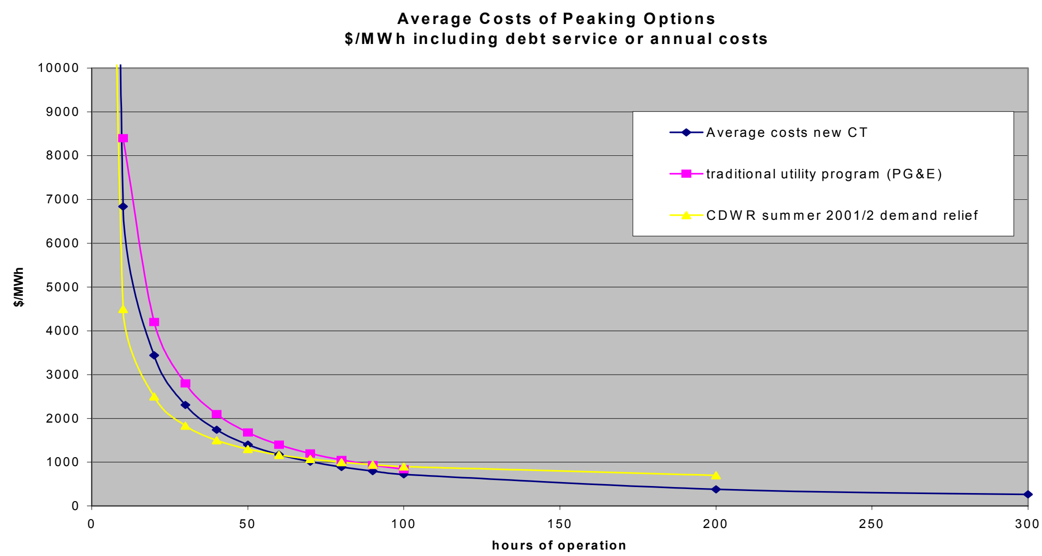
Cost Element	Interruptible Rate	ISO Demand Relief	A/C Cycling	RTP Rate
Program Design, Development, Approval	Low since rate already exists	Low since program has existed for two years	Low since UDCs presently operate such programs	Higher, since previous filings at the CPUC have been rejected, and UDCs have to adapt billing systems
Customer Marketing and Recruitment	Low, since most of likely participants already on this rate	Substantial, especially given disastrous "conversion" during June 2001	Substantial, since customers in SDG&E and PG&E largely unfamiliar	Low for pre-existing interest groups, but larger for medium-sized commercial buildings
Participant Equipment	Inexpensive, since low tech equipment suffices	Higher , since ISO requires interval metering and communications	Medium, since fixed equipment costs are low	State-funded RTP metering system is now a sunk cost for 13,000 MW of load
Operating Costs	Low costs to trigger program	Medium since energy reductions produce additional customer payments	Very low	Very low once UDC billing systems adapted
Incentive Costs	Very high, since rate rebate can mean extremely high "reservation" costs, whether used or not	Very high, since $20/kw-month is a high reservation payment	Relatively low as long as customers motivated by altruism to participate	Very low except when "reliability" adder used to preserve reliability. Can have net revenue increases depending upon financial arrangements

Potential Capacity from Load Curtailment Programs

There are no solid estimates of the potential capacity from load curtailment programs and RTP rate load reductions.[4] We know some things about customer willingness to participate in these programs. We know that more customers will participate if the probability of program operation is low than if it is high. We know that more aggregate load reduction can be obtained if the load reduction per customer is small compared to normal load. We know that the higher the incentive the greater the level of participation. We know that if the program is exercised very rarely, that levels of actual load reduction can drop when manual processes of communication and load shedding are the dominant methods of operation. Finally, given past experience with these programs and the state's pursuit of RTP metering systems for about 14,000 MW of load, that at least 3,000 MW of program capacity can be relied upon in California under program designs comparable to those that exist today.

Table III-3-3 provides a summary of the load curtailment capability that existed at the maximum for each program during 2001 and a conservative estimate of the capability that could be developed for 2002. For various reasons, the ISO and DWR have decided to abandon various demand responsive programs they operated in summer 2001. Some of the capability under these programs can be transferred to new or modified programs operated by UDCs under CPUC authorization if the program designs offered by the Energy Commission in R.00-10-002 are accepted.

Figure III-3-1
Comparison of Average Costs per kWh of Operating Demand Responsive Programs



Approximately 2,000 MW of demand responsive capability under new programs and tariffs could be achieved if the program design and funding proposals made by the Energy Commission to the CPUC result in favorable decisions by January 2002, and if marketing efforts aim to have programs capability on line by May 2002. A key difference between 2002 and earlier years is that every customer with loads >200 kW will have an RTP metering system in place and functioning due to state funding through AB1x-29. This should make marketing easier and reduce turnaround time between the time the customer agrees to participate and when they are operational.

Table III-3-3
Estimate of Aggregate Demand Responsive Capability by Program Type

ISO & CPUC Load Curtailment Programs and RTP Rates	2001 Program Capacity (MW)	Potential Program Capacity (MW)
CPUC Interruptible Tariff Program	1136	1200
A/C Cycling	300	500
Other CPUC programs (OBMC, etc.)	50	50
ISO Summer Demand Relief Program Rounds 1 & 2 *	200	0
ISO Discretionary Load Curtailment Program *	40	0
DWR Demand Bidding Program **	0-400	0
CEC Voluntary RTP tariff	0	1000
CEC-Proposed Modifications to CPUC-Authorized BIP and VDRP programs	25	1000
Total for Programs	**1751-2151**	**3750**

Notes:
*ISO has decided to terminate its own demand responsive programs for 2002.
** DWR/CERS interprets CPUC decisions to forbid recovery of Demand Bidding Costs in AB1x-1 revenue requirements, thus inducing DWR to withdraw the program.

Coordination of Funding and Program Authorization Among Agencies

Coordination among agencies responsible for demand responsive programs and tariffs left something to be desired during 2001. The credibility of demand responsive as a viable resource option has been questioned. The most serious challenges to demand responsive as a resource option are not, in fact, whether well designed and properly funded programs can be successfully marketed to consumers and operated with participants. Rather, the question is whether the disparate set of agencies can establish a unified and efficient program design soon enough to recruit participants for the 2002 summer season.

At this writing there are two CPUC forums in which demand responsive programs and tariffs for 2002 are under consideration. First, the CPUC has launched Phase 2 of R.00-10-002 to review funding and program design for all UDC programs for 2002 and beyond. An Assigned Commissioner Scoping memo was issued by Commissioner Brown and ALJ Mattson defining the nature of the issues and the schedule on September 21, 2001. Utilities and other parties filed comments in October and made final recommendations in November following a round of workshops. The CPUC contemplates a decision in this proceeding by February 2002, thus allowing sufficient time for marketing in order to have programs operational by May/June 2002.

Second, the CPUC's Rate Stabilization proceeding has received multiple proposals for voluntary RTP tariffs from the Energy Commission, UDCs and others. State law requires the CPUC to have an RTP tariff in place by the end of 2001 for purposes of valuing generation by certain grid-connected distributed generation technologies previously operating under net metering rules. Parties hope that the CPUC will adopt RTP tariffs that are more broadly applicable than just this limited domain. Numerous customer groups have supported RTP tariffs and are predisposed to voluntarily accept them if offered. These two forums offer some hope that a more coordinated and properly funded set of demand responsive programs and rates can be in place for the summer of 2002.

Recommendations

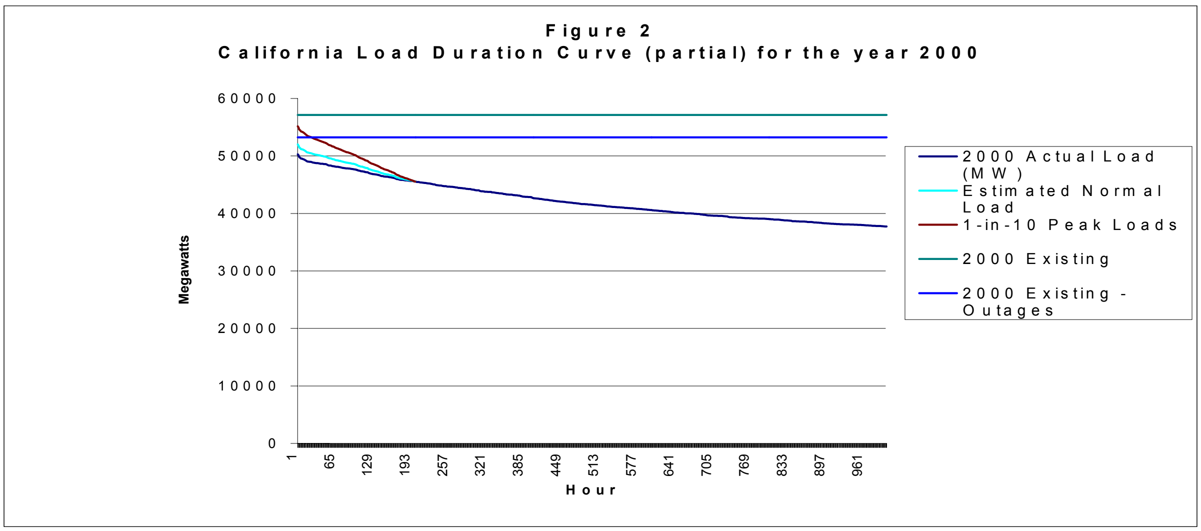
Examining the shape of the load duration curve of **Figure III-3-2** suggests that there are up to 5,000 MW of load that can be expected less than 200 hours per year. It is unreasonable to expect that 5000 MW of generation will be available from the bulk energy market to satisfy such loads. Private generation owners require sufficient cash flow to amortize their debt and obtain a reasonable profit. Building a peaker and holding it in reserve for highly stressed system conditions could only occur if market-based energy prices were allowed to skyrocket (not allowed through September 2002 by existing FERC orders), or if some entity were willing to make major contractual commitments outside of the market itself. Many market analysts believe that fundamental market redesign or explicit capacity payments are needed to ensure that generating resources are available just for peak load conditions.

Before California makes expensive commitments to reliably serve peak load, we must first assess what the correct level of system reliability should be. It is unclear how much end-users are willing to trade off reduced reliability in return for cost reductions. In other markets, rather than analyzing these issues in a planning process, the market itself is left to find the proper equilibrium through pricing. California is probably too gun-shy of "market solutions" to fully rely upon this approach. Yet, we will never learn how end-users value reliability until we provide them with pricing options that provide them with the proper incentives to reduce load under various price and system conditions. Developing some actual operating experience is essential to fully answering the question.

In its recommendations to the CPUC in R.00-10-002, the Energy Commission proposed that a total of 2,500 MW of planned demand responsive capability should be obtained from demand response - load curtailment programs and tariffs. We propose this level for two reasons.

First, this level should be sufficient to develop several different load curtailment programs and RTP rates. Offering sound load curtailment programs to end-users, and conducting a careful review of their response to marketing efforts will provide real data for measuring the effectiveness of program implementation and deployment. If a sufficiently large set of load curtailment programs are not offered, we will never gain the experience to know the extent to which these tradeoffs are acceptable to substantial numbers of customers. Thus, pursuing load curtailment program experience can help to firm up corollary benefits described in our use of the six comparison criteria. Testing the markets for demand response programs will help to develop longer run solutions.

Figure III-3-2
California Load Duration Curves
for Summer Months of Year 2000



Second, sole reliance upon generation to provide peaking resource needs violates our flexibility criteria. Committing too much of resource additions to peakers is imprudent given the potential that load curtailment programs and RTP rates appear to offer. Excessive commitment to peakers may drive out lower cost, more environmentally friendly and economically efficient solutions using RTP tariffs. The proper planning decision under these conditions is to minimize long term commitments, and to explore the options further.

Much remains to be determined about end-users' willingness to participate in demand responsive programs and tariffs. Unfortunately, we learned nothing in the summer of 2001 except that constantly changing program designs create great confusion in end-user minds and greatly increases the difficulty of marketing any programs. Our experience base with end-user response to demand responsive programs and rates is simply insufficient to be able to guarantee response. However, recent experience shows that at least some customers are perfectly willing to trade off reliability for reduced costs.[5] Making short term commitments to load curtailment programs achieves the overall goal of 2,500 MW of demand responsive capability, and can lead eventually to greater reliance upon RTP tariffs and less reliance upon load curtailment programs**.** The Energy Commission has already proposed specific modifications to two existing, CPUC-authorized load curtailment programs that would enable this 1000 MW of increased load curtailment program capability to be achieved.[6]

Endnotes

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1 Public Utilities Code sections 739.11 and 393 direct the utilities and the CPUC, respectively, to undertake various dynamic and other real-time tariff studies.

2 Hirst, The Financial and Physical Insurance Benefits of Price-Responsive Demand, www.Ehirst.com, January 2002.

3 Despite submission of a well-founded RTP tariff, and extensive support from likely participants, the CPUC rejected the Energy Commission's June and July 2001 proposals, and has scheduled no efforts to resolve their apparent concerns.

4 The Silicon Valley manufacturer's Group was a strong supporter, among other consumer groups, for the voluntary RTP tariff filed by the Energy Commission at the CPUC.

5 This is experience gained in California under the very difficult conditions of December 2000 to February 2001, a decade of experience with RTP tariffs in the Georgia Power system, and a smattering of recent experience around the rest of the nation.

6 CEC, Proposals of the California Energy Commission for Modified Demand Reduction Programs, R.00-10-002, November 9, 2001.

Chapter III-4 Effects of Renewable Generation Initiatives

Introduction

Renewable energy generation projects have been greatly affected by the restructuring of the electricity market in 1996 and the electricity crisis that began in 2000. Assembly Bill 1890, the bill that restructured the state's electricity market, called upon the Energy Commission to create a program that would enable renewables to compete in a deregulated marketplace. The Energy Commission responded by designing and implementing a market-based program aimed at supporting renewables from both the supply and the demand side. The electricity market crisis that began in the summer of 2000 threatens to reduce supply and demand for renewables. Because the crisis led to the elimination of direct access and the financial difficulties of the investor owned utilities, there is at present essentially no buyer for much of California's new renewable resources other than the newly created California Consumer Power and Conservation Authority, whose financing uncertainty has so far precluded it from purchasing any renewable generation. Environmentalists and consumer advocates argue that requiring the utilities and electric service providers to purchase renewable energy under the guise of a Renewable Portfolio Standard would stimulate demand for renewables. Although a proposed Renewable Portfolio Standard failed passage in the Legislature in 2001, it is likely to be reintroduced in the 2002 session.

The Energy Commission is currently evaluating and plans to continue the evaluation of policies aimed at providing a market for new renewable generation. This chapter discusses the following:

- How the electricity crisis has diminished market opportunities for new renewable generation facilities, stalled the State's progress in meeting its renewable energy goals, and threatened the long-term viability of the renewable energy industry.
- How a Renewable Portfolio Standard might interact with the Energy Commission's current and future proposed efforts for promoting renewables.
- The renewable generation implications of a return of direct access, along with the Power Authority's intentions to purchase renewable generation.

Background on California's Renewable Energy Industry

The Development of California's Renewable Energy Industry (1978-1996)

The federal Public Utility Regulatory Policies Act of 1978 (PURPA) spurred the development of the renewable industry in California. PURPA required that utilities purchase electric power from independent generators, many of which used a renewable resource such as biomass, wind, and solar energy to generate their electricity. Many of these renewable facilities signed ISO4 (Interim Standard Offer Number 4) contracts with the utility. ISO4 contracts provided fixed energy payments for 10 years, which were based on the investor-owned utilities forecasts of their own costs if they had generated the power themselves instead of purchasing it from the renewable generator, along with fixed capacity payments. The fixed capacity payments did not end in 10 years, but lasted the life of the entire contract. These contracts lasted as long as 30 years.

In the 11th year of the ISO4 contracts, the fixed energy prices converted to variable prices using a formula tied to the price of natural gas. These prices were as much as 85 percent lower than the fixed prices received at the end of the ten-year period, forcing 300 MW of renewables to go off-line between 1993 and 1997. Despite the drop in revenues for renewable generators, California developed of 6,600 MW of renewable capacity by 1996 that produced 12 percent of California's electricity usage.

Restructuring and Renewables (1996-1998)

When the state restructured its electricity market, there was concern that the "stranded benefits" inherent in the State's developed renewable industry would be lost in the transition to competition without governmental assistance. Generating electricity from renewable sources is generally more expensive than the cost of generation from fossil fuels but comes with public benefits that are difficult for the market to take into account. In a deregulated market, purchasers seek the lowest price. Since the State recognized the public good that is associated with renewables, AB 1890 authorized the utilities to collect $540 million from their customers from 1998 through 2001 to support the development of renewable resources. AB 1890 tasked the Energy Commission with recommending how these funds should be spent.

In March 1997 the Energy Commission submitted its recommendations for the allocation of the $540 million to the Legislature in a report entitled, *Policy Report on AB 1890, Renewables Funding: Report to the Legislature* (Policy Report). The Legislature incorporated most of the Policy Report's recommendations into Senate Bill 90 (Sher). The Energy Commission recommended the creation of a simple, market-based program that subsidizes supply (maintaining existing renewable capacity and constructing new renewables) and demand (educating customers on renewable resources and encouraging the purchase of renewables off the grid). Additionally, the Energy Commission recommended funding to subsidize emerging renewable resources, such as grid-connected photovoltaics and small wind turbines whose output is used on-site.

Building a Market for Renewables (1998-2001)

Before the electricity market crisis of 2000, the Energy Commission's Renewable Energy Program was instrumental in increasing the supply and demand of renewables within the market-based system of AB 1890 (**Figure III-4-1 and Figure III-4-2**). Developers came to the Energy Commission with more proposals for new renewable generating facilities than could be funded and by May 2000, 97 percent of all customers that participated in direct access bought renewable energy products off the grid.

Figure III-4-1
California's In-State Renewable Installed Capacity (2000)

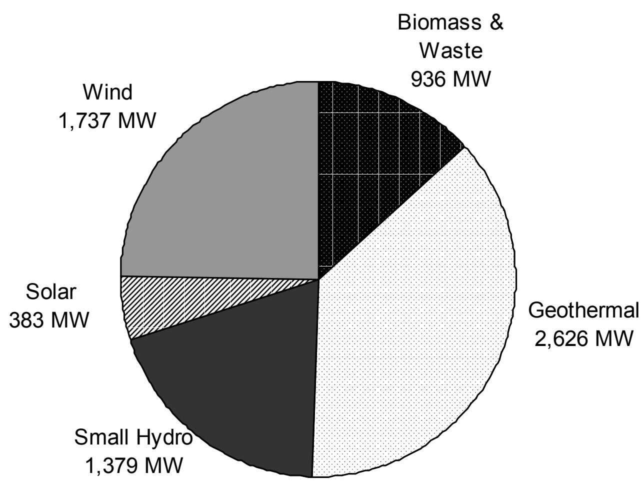
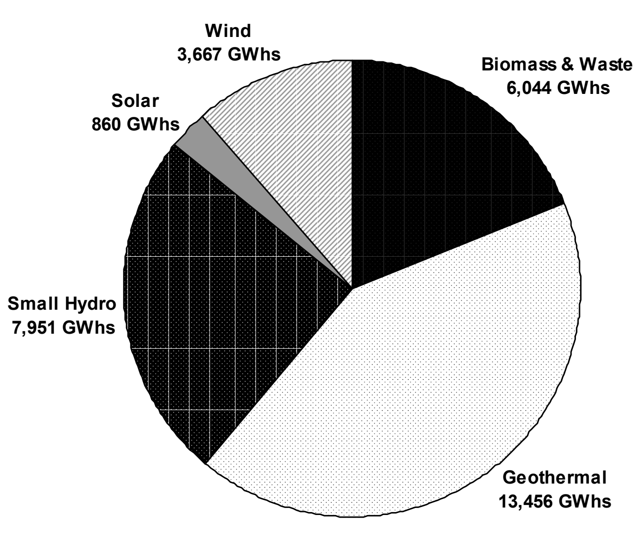


Figure III-4-2
California's In-State Renewable Energy Generation (2000)



In June 1998, the Energy Commission's Renewable Energy Program held a $162 million auction for new renewable generation. Funds for new renewables were distributed in an auction process whereby developers submitted bids in the form of a per kWh incentive payment from the Energy Commission. The Energy Commission accepted bids from lowest to highest until the $162 million was fully allocated. New renewable capacity receiving contingent funding awards as a result of this auction totaled 551 MW and the winners included a diverse array of renewable technologies such as geothermal, wind, and landfill gas.

In addition to promoting new renewables, the Energy Commission provided funds to ensure that existing renewables would stay on-line. As mentioned earlier, in the mid 1990s, renewable capacity decreased by 300 MW because of reduced payments from the utilities. The Energy Commission, through its assistance to Existing Renewables, provided incentive payments to these facilities when the utility payments were less than a target price. The 300 MW of lost renewable generation in the mid 1990s came back by 2001 along with other existing facilities that maintained their output or repowered their facilities.

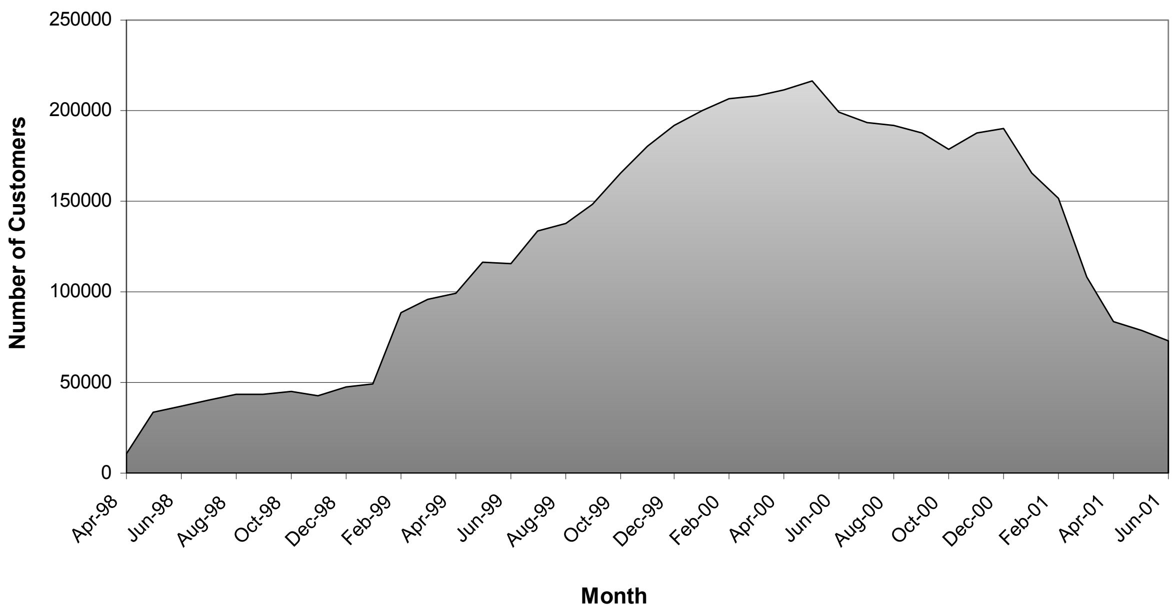
The Energy Commission also built demand for renewables by providing a per kilowatt-hour credit to customers who purchased renewable energy from a direct access electric service provider. At the market's peak in May 2000, over 216,000 customers (2 percent of all IOU customers and 97 percent of all direct access customers) received a credit of 1.25 cents/kWh on their electric bill for purchasing renewable energy.

The Energy Crisis and Renewables

The electricity crisis threatens the long-term viability of California's renewable resources. On the supply side, existing renewable facilities went up to five months without payment for their generation and the California Power Exchange, seen as a market for the output of renewable facilities, went bankrupt. In 2001, legislators proposed the Renewable Portfolio Standard that would act as a mechanism to stimulate demand for renewables. To spur the development of new renewables, the Energy Commission held two more auctions for $40 million each, one in November 2000 and the other in September 2001. Combined, these two auctions yielded 770 MW (nameplate) of potential new renewables. Whether these projects (as well as some 1st auction projects that are not yet on-line) come to fruition, however, depends on whether they can find a buyer for their power.

On the demand side, Electric Service Providers exited the market, further diminishing renewable generators' power sale opportunities. At the market's peak in May 2000, 216,000 customers purchased renewable energy products, then shrinking to 73,000 in June 2001 (**Figure III-4-3**).

Figure III-4-3
Number of Customers Purchasing Renewables from a Direct Access Provider



Renewables Funding is Extended Until 2012

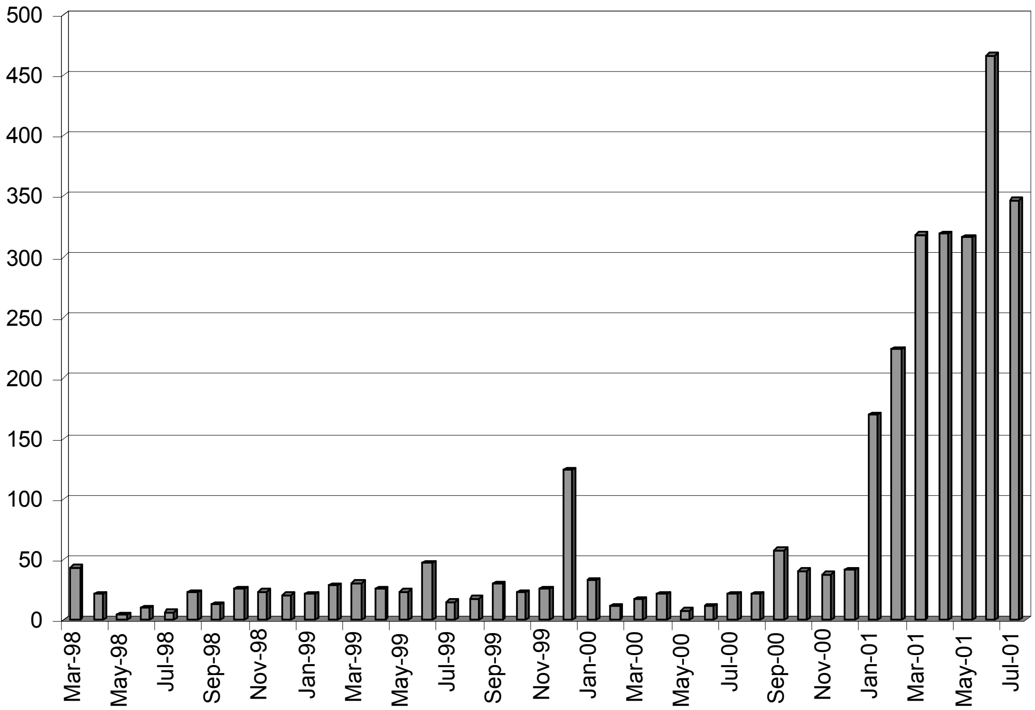
In September 2000, the Governor signed Assembly Bill 995 and Senate Bill 1194, the Reliable Electric Service Investments Act. The Act extended the collection of the public goods charge that funds the Energy Commission's efforts in promoting renewable resources. Language in the Act indicated that the Legislature intended that the Energy Commission's efforts in renewables contribute to the solution to the electricity market crisis by providing additional generation while reducing reliance on natural gas. The investor-owned utilities will continue to collect $135 million per year, adjusted for inflation, from 2002 until 2012. The Act also required the Energy Commission to create an investment plan for the Legislature's consideration recommending an allocation of these funds collected over the first five years of the collection period. The Act also required the Energy Commission to recommend numerical targets, or projections for the growth of renewables in California's power mix during the years covered by the investment plan. The Energy Commission submitted these recommendations to the Legislature in June 2001 in *Investing in Renewable Electricity Generation in California: Report to the Governor and Legislature* (Investment Plan). Governor Davis endorsed the recommendations in the Investment Plan along with the proposed target that 17 percent of California's electricity consumption be renewable by 2006. While the Investment Plan did not get enacted into law during the 2001 Legislative session, it will be reconsidered during the 2002 session.

The Investment Plan recommended that $337.5 million or 50 percent of the funds be allocated to new renewables to meet the Energy Commission's recommended target of 17 percent renewable energy by 2006. The allocation for Existing Renewables, 20 percent, was reduced from the 45 percent allocation during the SB 90 program, because of higher forecasted energy prices during the 2002-2007 period and the lower cost of renewable technologies including geothermal, landfill gas, and small hydro no longer qualify for funding.

On the demand side, the Energy Commission recommended a 10 percent share of funding for rebates for customers that purchase renewables from a direct access provider. Although Assembly Bill 1X required the California Public Utilities Commission to suspend direct access for new customers, the Energy Commission wanted to preserve the current level of direct access demand for renewables. Effective in 2003, the Energy Commission proposed that to qualify for a credit for the purchase of renewables off the grid, customers would be required to purchase new renewable resources to stimulate the construction of New Renewable generation.

In its targets for renewables, the Energy Commission stated a goal of having 1 percent of all electricity consumption in California come from emerging renewables by 2006 and recommended an allocation of 15 percent of total funds to emerging renewables. Interest in emerging renewables increased dramatically as concerns about rolling blackouts and increases in electricity rates improved the economics of photovoltaics (**Figure III-4-4**). Although emerging renewables represent less than 1 percent of the electricity generated in California, demand for funding from the Energy Commission's Emerging Renewables Buydown Program increased over 1,000 percent from the third quarter of 2000 to the third quarter of 2001. Additionally, in August 2000, the Legislature passed AB 970, which required the California Public Utilities Commission to develop and administer a program that encouraged distributed generation that increased the reliability of the electricity system. The California Public Utilities Commission developed a program that provides rebates of $4.50 per watt for renewable distributed generation systems. The Energy Commission in May 2001 increased the rebate level for emerging renewables from $3.00 per watt to $4.50 per watt. AB 29X, in April 2001, allocated an additional $15 million to the Emerging Renewables Buydown Program. In another proposal to stimulate demand for emerging renewables, the Governor signed SB 17X2 in October 2001, which provides a 15 percent tax credit for emerging renewable systems under 200 kW through 2003.

Figure III-4-4
Requests for Funds from the Emerging Renewables Buydown Program



Assembly Bill 1X and the Bankruptcy of the Power Exchange

Both the implementation of Assembly Bill 1X and the bankruptcy of the Power Exchange affected the market for renewables in California. AB 1X, signed February 1, 2001, brought the state, through the Department of Water Resources into the position of purchasing electric power for customers of California's Investor Owned Utilities. The Department of Water Resources signed long-term contracts to supply most of the power to meet IOU customers' needs, but signed relatively few contracts with renewable generators. Additionally, Assembly Bill 1X ordered the suspension of direct access. The bankruptcy of the Power Exchange, the financial difficulties of the utilities, and the suspension of direct access eliminated opportunities for new renewable power plants to sell their generation.

Similar to Assembly Bill 1X, the demise of the Power Exchange also presented obstacles for California's renewable resources. The 1,300 MW of projects that received awards in the Energy Commission's three new renewable auctions no longer had a "backstop" market in which to sell their power. With the Department of Water Resources purchasing only small quantities of renewable energy and Electric Service Providers and utilities unable or unwilling to purchase renewable power, combined with the Power Exchange's bankruptcy, the possibility arose that many of the 1,300 MW of new renewables awarded contingent Energy Commission funding may never be built. Because these developments created concern over the viability of demand for renewables, consumer advocates and environmentalists proposed a Renewable Portfolio Standard, whereby electricity retailers would be required to purchase a certain percentage of their power from renewable resources.

The State Provides Further Assistance to Renewables

The Legislature, in 2000 and during two special sessions in 2001, enacted legislation that authorizes further financial support for renewables in addition to the Energy Commission's Renewable Energy Program.

The Legislature established the California Technology, Trade, and Commerce Agency's Agricultural Biomass-to-Energy Incentive Grant Program through AB 2872 to provide $10/ton for the utilization of agricultural residual materials to produce electric power. As presently construed, starting in 2002 any biomass facility that receives funding from this Program will not be eligible to also receive Energy Commission assistance. In November 2000, Governor Davis announced that the Technology, Trade, and Commerce Agency awarded $9 million in grants to 11 biomass facilities in the Central Valley.

The Technology, Trade, and Commerce Agency also administers the Renewable Energy Loan Guarantee Program, created by Assembly Bill 29X. The $40 million Renewable Energy Loan Guarantee Program guarantees loans ranging from $25,000 to $2 million per project.

AB 29X also created a $25 million program within the California Alternative Energy and Advanced Transportation Financing Authority, which can provide loans and grants to developers of renewable projects. Neither of these AB 29X programs are operational at this time. Finally, AB 29X authorized an additional $15 million to increase rebate levels for the Energy Commission's Emerging Renewables Buydown Program.

Of all the new additions to the State's involvement in promoting renewables, the California Consumer Power and Conservation Financing Authority potentially has the most resources in terms of its powers and funding to expand the supply of renewable resources. Senate Bill 6X created this new agency to ensure that California achieves a reliable and secure energy system at lowest cost to consumers. The California Power Authority can utilize up to $1 billion of its bond authority to make loans for renewables, efficiency, and conservation. In September 2001 it announced that it signed 14 letters of intent with 2000 MW of renewable capacity. These letters indicate a desire to negotiate, but are not an agreement to purchase generation.

Market Uncertainty and its Effects on Renewables

In the last week of the 2001 legislative session, the Assembly and Senate heard bills that would have affected both the supply and demand for California's renewable resources. The Legislature considered enacting the Energy Commission's Investment Plan, the Renewable Portfolio Standard, and a proposal to allow utility customers to choose direct access if they purchased a product that was at least 80 percent renewable. None of this legislation passed during the 2001 Legislative session. While these initiatives will be reconsidered next year, the uncertainty facing California's renewable resources continues as 2001 comes to a close. Will demand come from a Renewable Portfolio Standard or direct access, or will the Power Authority sign power purchase agreements with renewable generators? Since the Renewable Investment Plan failed to pass the Legislature, the Energy Commission cannot spend public goods funds collected for renewables in 2002 without legislative authorization. It is uncertain when this authorization will come.

From 1998 through 2001, the Energy Commission has awarded funding to developers of 1,300 MW (nameplate) of new renewable capacity. These funding awards are contingent on the plant becoming operational. The possibility exists that these projects may never get built unless a buyer is found for their generation.

There are questions surrounding the implementation of policies aimed at stimulating demand for renewables. The quantity and timing of the purchase of renewable generation by the California Power Authority remains to be seen. It is unknown whether or not a Renewable Portfolio Standard will be enacted or if direct access will be reestablished. A resolution of these issues can reduce the market uncertainty facing the renewable energy industry.

Building Future Demand for Renewables: Direct Access and the Renewable Portfolio Standard

A proposal to create a Renewable Portfolio Standard in California appeared in Senate Bill (SB) 532 during the 2001 session and is expected to be reintroduced in some form during the 2002 session. Under the Renewable Portfolio Standard, the investor-owned utilities, electric service providers, and the Department of Water Resources (as long as it is purchasing power for utility customers) must ensure that a specified portion of electricity they sell is generated by a renewable resource. The Renewable Portfolio Standard concept is simple: requiring that renewables comprise a certain percentage of electricity consumption creates its own market demand. The idea of requiring a certain percentage of renewable production appears simple but there are underlying issues surrounding the implementation of an Renewable Portfolio Standard.

SB 532 proposed that the Energy Commission would administer the Renewable Portfolio Standard Program. Only new renewable generation would qualify for the Renewable Portfolio Standard. Retail sellers of electricity would satisfy the Renewable Portfolio Standard by procuring credits that equal a kilowatt-hour of renewable generation. The Energy Commission would issue credits to the generators who in turn would sell those to the retail sellers. The Energy Commission would design an accounting system that would verify the generation from the new facilities and verify retail sellers' compliance with the Renewable Portfolio Standard. Under one version of the Renewable Portfolio Standard, credits could not be sold at a price greater than 1.5 cents/kWh. A retail seller that did not satisfy its credit purchasing obligations would pay a penalty.

There are costs to implementing a Renewable Portfolio Standard, which are in essence subsidies to the renewable energy industry. The retail sellers would be required by law to purchase credits from renewable generators. Concerns have arisen about how this would affect electricity costs. By forcing the retail seller to undertake the additional cost of purchasing renewables, rates may have to rise. The rules governing an Renewable Portfolio Standard could include a cap on the cost of procuring credits, but a cap hinders the ability of the State to meet the standard. A Renewable Portfolio Standard would more likely be met if the cost remained uncapped. Some renewable generators may require a subsidy that exceeds the cap to come on-line. Under the Energy Commission's present program, the amount of incentive that will be paid to a new renewable facility is known in advance. Under a credit-trading scheme, it is unknown how much a credit will cost on a per kilowatt-hour basis.

If the State of California enacts the Renewable Portfolio Standard, the program should be consistent with the Energy Commission's current efforts in promoting renewable energy. Participants in the Renewable Portfolio Standard program and the Energy Commission's current program would follow straightforward and consistent regulations if the programs were jointly administered. For example, the same renewable technologies that qualify for satisfaction of the Renewable Portfolio Standard should be the same as those for a new account auction. Combining an Renewable Portfolio Standard with the Energy Commission's present program raises concerns about over subsidizing new renewables. The Energy Commission could prevent excessive subsidies by capping the combined amount that new renewables receive from both a New Account auction and through the sale of credits.

Currently, the Energy Commission encourages demand for renewables by paying a credit to customers that purchase renewable products through a direct access contract. A Renewable Portfolio Standard and a program to encourage direct access purchases of renewables can co-exist, and with direct access, demand for renewables could be further stimulated. Customers may want to purchase all of their electricity from renewable resources while the amount of renewables required for purchase under the SB 532 Renewable Portfolio Standard proposal might be much less. In September 2001, the California Public Utilities Commission voted to freeze direct access participation. On the other hand, the Legislature considered SB 27XX, that allowed electric service providers to acquire new customers as long as those customers purchase a product that is at least 80 percent renewable. Direct access was suspended because of concerns that it would exacerbate the Department of Water Resources cost recovery. SB 27XX aimed to alleviate concerns by proposing an exit fee for leaving utility service and an entry fee if that customer returned to the utility. Under this scenario, the Energy Commission could perhaps use renewables funding to reimburse customers for the entry and exit fees.

Conclusion

The switch to deregulation in 1998, the electricity market crisis, and the solutions undertaken by the state to alleviate the market crisis have had profound effects on the supply of and demand for California's renewable resources. Some new renewable generation funded through the Energy Commission's three auctions may never get built due to the current uncertainty over who will buy this generation. It is unknown whether, or if, the Legislature will restore direct access or enact a Renewable Portfolio Standard. The Department of Water Resources has purchased only limited amounts of renewable generation and the Power Authority is not yet in a position to finance or acquire renewable resources. The investor-owned utilities are undergoing financial difficulties and the remaining electric service providers cannot sign up new customers. To respond to changing conditions, the Energy Commission needs to maintain its flexibility in determining the allocation and distribution of funds for its efforts in renewable energy.

The Energy Commission will continue to support emerging renewable resources such as photovoltaics, wind turbines under 50 kW, solar thermal electric, and fuel cells that utilize renewable fuels because of their technical potential. The cost of photovoltaic systems has decreased substantially in the last three decades, and this trend will continue. Further support for emerging renewables will stimulate demand for these technologies, which in turn, will stimulate that industry to devise ways to reduce costs such as training additional installers and technological innovations that simplify the manufacturing process. The recent increase in demand for on-site generation in response to California's energy crisis should motivate manufacturers, retailers, and installers of emerging renewables to reduce costs. In its Investment Plan for renewables, the Energy Commission hopes that one percent of all electricity consumed in California comes from an emerging renewable resource by 2006. The effective promotion of renewable resources requires the flexibility to navigate through various regulatory and market scenarios.

The legislation extending the Energy Commission's program stated renewables would add needed generating capacity while promoting fuel diversity and reducing the need to burn fossil fuels. Additional renewable resources can come on-line and meet these goals if the Energy Commission continues to have flexibility in administering its funds and if viable demand for renewables materializes.

Chapter III-5 Siting Issues

Introduction

In response to the energy crisis, the Commission has taken steps to expedite the licensing of new power plants. This chapter discusses these recent changes to the licensing process, current trends in licensing power plants, the interactions of transmission constraints with power plant licensing, the outcome of the new expedited review process, and remaining constraints to power plant licensing. This chapter finishes with suggestions to help alleviate some of the licensing constraints.

Background on the Licensing Process and Its Recent Changes

The Warren-Alquist Act, passed in 1974, gave the Energy Commission exclusive siting authority over thermal electric generating power plants 50 megawatts (MW) or larger and related facilities, such as transmission lines. The Energy Commission's standard licensing process is a 12-month Application for Certification (AFC). **Table III-5-1** "Comparison of Energy Commission Permitting Processes" provides an overview of the licensing processes available to developers. As the lead agency under the California Environmental Quality Act (CEQA), the Energy Commission reviews a developer's proposal to construct and operate a power plant. During the AFC review, the Energy Commission determines if a power plant proposal will comply with applicable laws, ordinances, regulations or standards; will result in potentially significant adverse environmental or public health and safety impacts; or will result in impacts to the electrical system's reliability. Based on its review the Energy Commission establishes conditions governing the construction and operation of the power plant, which will ensure compliance and avoid or mitigate identified significant impacts.

The Energy Commission may license a project that results in significant environmental impacts if it finds there are no feasible mitigation measures or project alternatives that would avoid or lessen the impacts, and that the benefits of the project outweigh the unavoidable significant environmental impacts.[1] The Energy Commission has the authority to override local, regional or state regulations if it makes findings that the power plant is needed for public convenience and necessity and there are no more prudent and feasible means of achieving such convenience and necessity.[2]

In response to California's looming energy crisis, the Legislature passed Assembly Bill (AB) 970 in September 2000, which established an expedited six-month licensing process for power plants that conform with applicable laws, ordinances, regulations, and standards, and have no significant environmental or public health or safety impacts. In May 2001, the Legislature passed Senate

Bill (SB) 28X, which expanded the expedited six-month AFC process to include repowering projects. Both bills establishing the six-month AFC sunsets on January 1, 2004.

AB 970 also established an expedited four-month licensing process for simple cycle power plants without significant environmental impacts for which the application was deemed complete by October 31, 2000. Because of California's critical shortfall in generation resources, the Governor signed Executive Order D-26-01 in early 2001 that reinstated the four-month process for simple cycle power plants that could be in operation by August 1, 2002. It also allowed the Energy Commission to suspend provisions of its regulations that would hinder the addition of new generation by 2002. SB 28X also reinstated the four-month AFC process for simple cycle power plants than can be operational by December 31, 2002, and required those power plants to convert to combined cycle or cogeneration facilities, if they were to operate more than 3 years. The expedited four-month AFC provisions of SB 28X sunset on January 1, 2003.

The Energy Commission also has a Small Power Plant Exemption process, which applies to power plants less than 100 MW that will not result in substantial adverse impacts to the environment or energy resources. As the lead agency, the Energy Commission conducts an initial study to determine whether the power plant meets these criteria. If the Energy Commission issues a negative declaration, and thus grants the exemption from its permit authority, the developer must seek applicable local, regional, or state permit approvals.

Executive Order D-26-01 directed the Energy Commission to initiate an emergency power plant licensing process pursuant to Public Resources Code section 25705 for projects that could be brought on line by July 31, 2001. Executive Order D-28-01 extended this process to projects that would be on line by September 30, 2001 by. This process is no longer available for licensing power plants.

With the passage of AB 970, the Governor's executive orders, and the passage of SB 28X, the Energy Commission has seen substantial increases in the number of applications submitted in 2000 and 2001. **Figure III-5-1** "Applications Filed" shows trends in the number of new power plants being proposed since the early 1990s.

Table III-5-1
Comparison of Energy Commission Permitting Processes Available to Developers in 2001

Process	Characteristics	Potential Issues	Process Features
Standard Permit 12-Month Application for Certification	• All power plant types • Especially baseload power plants or plants with long fuel supply or transmission lines	For projects having potential • Public health or safety concerns • Significant environmental impacts • Electrical system impacts • Legal compliance issues • Significant public controversy • Environmental justice issues	• "EIR" type environmental review • Public workshops and hearings in the community • 30-day public review of proposed decision • Agency input within 180 days • Conditions – construction, operation, closure • Override authority if appropriate • Compliance monitoring
Expedited Permit Expedited Six-Month AFC	• All power plant types • Repowering power plants	For projects with: • No public health or safety concerns • Mitigated environmental impacts • No electrical system impacts • Conformance with legal requirements • Little or no public controversy • Site control	• "Mitigated Negative Declaration" environmental review • Public workshops and hearings in the community • 15-day public review of proposed decision • Agency input within 100 days • Conditions – construction, operation, closure • Override not expected • Compliance monitoring
Simple Cycle Power Permit Expedited Four-Month AFC	• Simple Cycle power plants • Application filed by December 2001 1/ • Operational by August 2002 • 3-year operating limit unless refile 1/	Simple Cycle projects with: • No public health or safety concerns • Mitigated environmental impacts • No electrical system impacts • Conformance with legal requirements • Little or no public controversy • Site control	• "Mitigated Negative Declaration" environmental review • Public workshops and hearings in the community • 15-day public review of proposed decision • Agency input within 90 days • Conditions – construction, operation, closure • Override not expected • Compliance monitoring
Small Power Plant Exemption Four-Month Exemption Process	• All power plant types less than 100 MW • An exemption from Energy Commission's authority not a license	For projects with: • No Public health or safety concerns • No or mitigated environmental impacts	• "Mitigated Negative Declaration" environmental review • Public workshops and hearings in the community • Local, regional and state agencies issue permits • 30-day public review of proposed decision • Exempt conditions – construction, operation, closure
Emergency Permit **Process is no longer available**	• Peaking power plants • Operational by September 2001 • 3-year or longer operating limit	Peaking projects with: • No public health or safety concerns • Mitigated environmental impacts • No electrical system impacts • No or minimal linear facilities • Site control	• Exempt from CEQA • Fatal Flaw Analysis • 2 public hearings • Limited public review • Agency comments in 10 days • Conditions – construction, operation, closure • Compliance monitoring

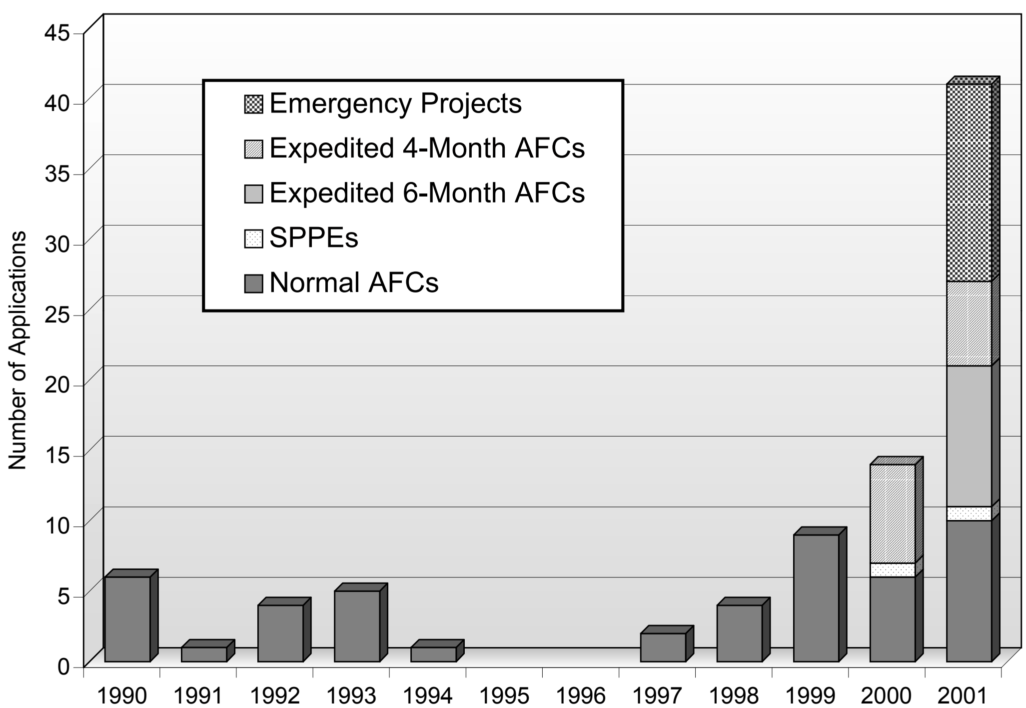
1/ Executive Order D-26-01 established a sunset for complete applications of 12/31/01, and requires projects to be operational by August 31, 2002. SB 28 X requires projects to be operational by December 31, 2002, and the legislation sunsets on January 3, 2003. SB 28X requires applications to refile as combined cycle or cogeneration if they are to operate more than 3 years, Executive Order D-26-01 does not.

Trends in Licensing Power plants

Approved Capacity Additions 2001-2004

The Energy Commission successfully licensed new power plants and expedited construction of approved power plants to help meet the summer of 2001-electricity emergency. **Figure III-5-2** "Approved Cumulative Capacity Additions" shows the approved capacity additions that will come on line between 2001 through 2004. The capacity additions shown in 2001 are currently operating (1,864 MW). Simple cycle power plants were licensed in 2001 through the Emergency licensing process. Combined cycle and cogeneration power plants were licensed through the standard 12-month AFC process and were approved prior to 2001. The Energy Commission helped the developers overcome obstacles to completing construction of these power plants to meet the emergency. Because of changing market conditions, there is some uncertainty whether power plants currently in financing (1,131 MW) will

Figure III-5-1
Applications for Power Projects Filed Between 1990-2001



begin operation as planned. Once construction has begun on a power plant, however, it is likely to be completed and the power plant is expected to begin operation as planned. Historically, some approved projects did not begin construction because of changes in market conditions, lack of financing or site control, or insufficient geothermal resources. Since the electricity industry was restructured, only two approved projects are not now expected to begin construction and are not shown in **Figure III-5-2**.

Potential Capacity Additions 2002-2005

Figure III-5-3 "Potential Cumulative Capacity Additions" shows potential cumulative capacity additions from 2002 to 2005, including the approved capacity additions shown in **Figure III-5-2**. The potential capacity additions for each year also include applications that are currently in data adequacy review, currently under review, and those that have been publicly announced by the proponent but for which the Energy Commission has not yet received an application.

Figure III-5-2
Approved Cumulative Capacity Additions

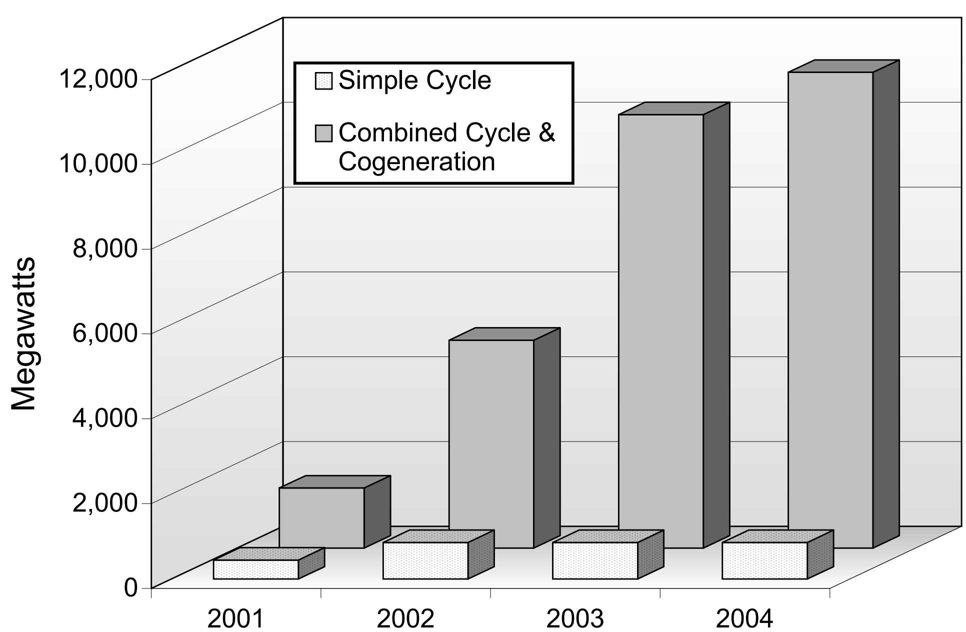
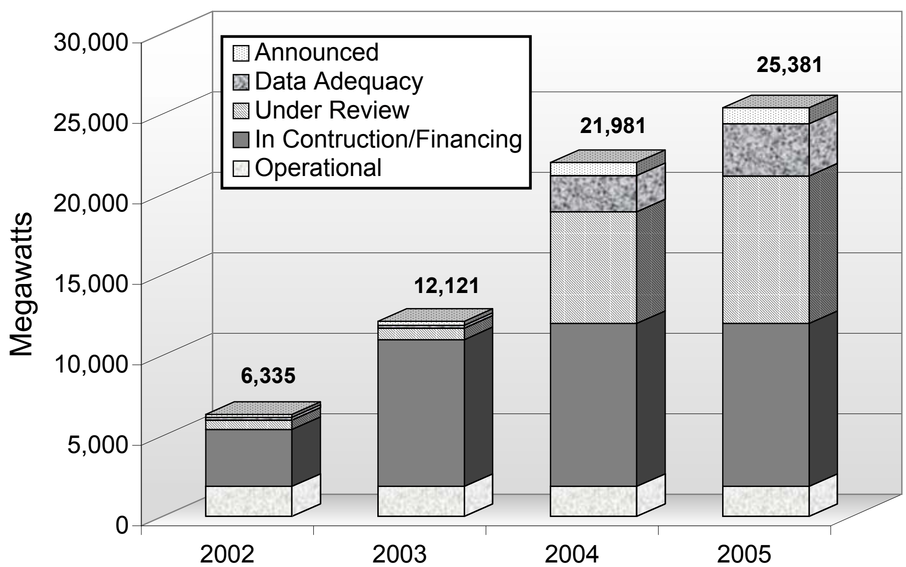


Figure III-5-3
Potential Cumulative Capacity Additions



How Realistic are These Capacity Addition Projections?

There is substantial uncertainty whether all of the capacity (25,570 MW) shown in **Figure III-5-3** will be brought on line as indicated. Some of the market conditions that make the potential capacity additions uncertain are discussed in Chapter II-2 "Integrated Supply-Demand Scenarios." Market conditions and siting constraints will determine whether all of the capacity additions shown in **Figure III-5-3** are cost effective for developers to pursue. Developers appear to be delaying filing of applications for some power plants and have indicated they will now not file applications for 9,500 MW (not shown in **Figure III-5-3**) that they had previously identified plans for building.

Developers sometimes fail to complete the licensing process for a variety of reasons, including lack of conformance with applicable regulations, inability to resolve environmental issues, cost of transmission congestion, insufficient fuel supply, and changing market conditions. Since the electricity industry was restructured, fifteen applications have been withdrawn (approximately 2,175 MW, not shown in **Figure III-5-3**). Two projects are currently in suspension (810 MW), and seven have not yet been deemed data adequate (3,250 MW included in **Figure III-5-3**). The current trend appears to be that developers are slow in making their applications data adequate.

Size and Type of Capacity Additions

In addition to the significant increase in the number of applications being filed, the size and type of power plants has changed in the restructured market. In the 1980s and early 1990s, the average capacity of proposed power plants was 150 MW. Since the electricity industry was restructured, developers have proposed much larger power plants, with an average capacity of 650 MW. The exceptions are the emergency and simple cycle power plants, which have an average capacity of 90 MW.

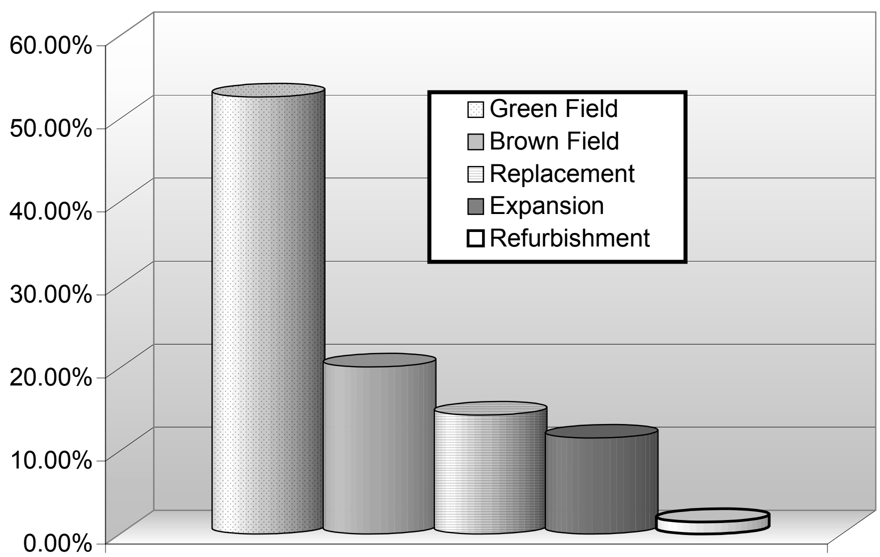
In the 1980s and early 1990s, developers proposed projects using a variety of technologies and fuel types, including natural gas-fired cogeneration and combined cycle, geothermal, coal, municipal solid waste, and solar power plants. The predominant type of power plant proposed was natural gas-fired cogeneration. In the late 1990s through 2001, however, the only types of power plant applications filed were natural gas-fired combined cycle, simple cycle, and cogeneration power plants.

Environmental Implications of Capacity Additions

Figure III-5-4 “Site Types” shows the distribution of site types for proposed power plants. Of the applications received, 54 percent have been located on undeveloped (green-field) rural sites and 46 percent have been located on previously disturbed (brown-field) sites. Of those located on previously disturbed sites, 55 percent have been replacements, expansions or refurbishments of existing power plants. The remaining brown-field sites are existing industrial sites not previously used for power plant development.

Environmental trends related to power plant development are described in the Energy Commission report *Environmental Performance Report of California’s Electric Generating Facilities*, published in July 2001. The siting trends observed since the electricity system was restructured raise concerns about the future environmental performance of the electricity system. First, developers appear to favor new green field sites rather than the clean up and reuse of existing power plant sites. Reuse of existing sites would be expected to improve system energy efficiency, reduce air emissions, water supply and quality impacts, and improve visual aesthetics. Second, power plant developers favor natural gas-fired generation capacity, which raises concerns regarding lack of fuel diversity, system reliability, and the cost of electricity.

Figure III-5-4
Site Types



Location of Capacity Additions

Power plant development is being proposed throughout the state. **Table III-5-2** "Capacity Additions by County" identifies the counties where power plant development under the Energy Commission's jurisdiction has been proposed, the megawatt capacity for approved power plants in operation, under construction and in financing. It also identifies power plants currently under review and power plants which have been announced by the proponent but for which the Energy Commission has not yet received an application. Development of power plants greater than 50 MW is proposed in 23 of California's 58 counties, the highest megawatt additions are in Kern, Riverside, Alameda, San Bernardino, and Contra Costa counties.

The location of new capacity additions is an import aspect of the supply and demand balance. Optimally, a percentage of all generation serving a load center should be located within the area of the load center. That percentage varies by load center and depends on generation and transmission constraints. The California Independent System Operator (CAISO) prefers to have generation located close to load, since this will reduce transmission congestion costs and line losses for generators. That is not to say that capacity additions cannot be added away from load centers, but there are costs and risks associated with siting capacity remote from load centers. Many of the capacity additions shown in **Table III-5-2** are remote from the load centers they will serve.

TABLE III-5-2
Capacity Additions by County

Location	Operational	Construction	Finance	Data Adequacy Review	Under Review	Announced	Total
Alameda					2,820		2,820
Colusa County					500		500
Contra Costa	555	1,410					1,965
Fresno					1,100		1,100
Imperial						180	180
Kern	320	2,563	500	100	250	86	3,819
Kings	95				691		786
Los Angeles					1,014	96	1,110
Merced				80			80
Monterey	50	1,060					1,110
Orange		450					450
Placer				900			900
Riverside	135	520		670		560	1,885
Sacramento				1,000	560		1,560
San Bernardino	80	1,776					1,856
San Diego	188	510		500			1,198
San Francisco					540		540
San Joaquin					169		169
San Luis Obispo					1,200		1,200
Santa Clara	90	645			315	70	1,120
Shasta			500				500
Solano		51	51				102
Stanislaus			80				80
Sutter	540						540
Total	2,053	8,985	1,131	3,250	9,159	992	25,570

Transmission Reliability and Congestion

When a new power plant is proposed, the Participating Transmission Owners and CAISO evaluate whether the power plant's interconnection to the transmission grid will adversely effect system reliability. Downstream reliability impacts typically are caused when new generators connecting to the transmission system over load transmission lines, transformers, circuit breakers, and other system components causing violations of accepted reliability criteria. Violation of these reliability criteria can result in system outages. Some reliability criteria violations may be mitigated through remedial action schemes, such as measures that would curtail generation from the new power plant during emergency conditions. Others may require transmission line expansion or replacement, or addition of transformers, circuit breakers, or other system components.

Transmission congestion can also affect the siting of new generation facilities. Congestion refers to increased loading on transmission line and equipment. But unlike reliability problems, the grid operator is able to dispatch generation to reduce congestion so that the system can still serve load without violating reliability standards. Increased congestion usually causes higher transmission delivery costs. The addition of new generation resources to the grid may create new or aggravate existing congestion problems, with multiple effects. Remedial action schemes can be employed to reduce congestion and ensure system reliability, but newer more efficient generation is likely curtailed. At some point, it becomes necessary to identify longer term more costly solutions than remedial action schemes to address congestion problems, such as transmission expansions. One significant problem for transmission planners is determining which of these many solutions is the most cost effective, in the absence of knowing where in the state future power plants will be proposed. In many cases, the generation is being constructed faster than answers to the questions can be determined, and system reliability may suffer. A multi-agency and generation and transmission stakeholder state planning effort needs to be established to address these problems. Another significant problem is determining who pays for congestion and transmission system expansion. This may be a more difficult problem not likely be addressed through the planning process.

How Successful Are the Emergency and Expedited Review Processes?

The Energy Commission's experience with the emergency and expedited review processes is limited, so it is probably far to soon to reach firm conclusions regarding their overall effectiveness. The licensing phase is only one element of the complex process to plan, construct and operate new power plants. The Energy Commission's efforts during the electricity emergency to conduct early site screening for the emergency projects, to assist developers in processing project compliance amendments, and to assist developers in overcoming roadblocks to completing construction were just as important for bringing new capacity on line as the expedited licensing process.

The emergency licensing process had a short review time of only 21 days. Of the fifteen applications for emergency projects (1,319 MW), the Energy Commission approved nine (926 MW); one was later canceled (62 MW), and one project is having difficulty beginning operation as planned (180 MW). The success of the emergency process is largely the result of early site screening, developers already having site control and generation equipment ordered. However, the emergency process suffered from lack of a formal environmental review process and limited public participation because of the short review time. The process was successful in the short-term, by adding 449 MW for the summer of 2001 and 683 MW by the end of 2001. However, without a clear and understandable emergency, this process could erode the public's trust in the siting process. The emergency process is no longer available to developers, and it is not clear that this process would necessarily be the best way to meet critical short falls in supply in the future.

The expedited four-month AFC process for simple cycle projects, which includes a formal environmental review, was the next shortest licensing process. The Energy Commission has received thirteen expedited four-month AFCs. Two four-month AFCs were approved, one of which has failed to gain site control and may not be constructed and operated; four are currently under review; one is in data adequacy review; and six have been withdrawn. Of the four AFCs under review, three appear to be having difficulties in meeting the schedule for approval. If there are issues, the short review time for this licensing process makes it difficult to ensure timely input from the public or local and state agencies. In addition, this process is limited to simple cycle power plants, which may not be as competitive in the electricity market as base load combined cycle or cogeneration power plants over the long term.

To file a six-month AFC, a developer must propose a power plant that avoids complex environmental issues, has site control, avoids land use and zoning conflicts, and does not result in system reliability problems. The Energy Commission received seven expedited six-month AFCs; three are in data adequacy, one is in suspension, and three are under review. Because two of the projects failed to meet all the criteria for a six-month AFC, staff has recommended that they be processed under the 12-month AFC process. In order for the expedited six-month AFC process to be successful, the Staff believes that developers need to carefully select sites and design their proposals to avoid or mitigate any environmental or system reliability impacts prior to submitting their application for review by the Energy Commission.

Siting Constraints

Based on recent licensing cases, critical issues that may impact the development of new power plants include the availability of emission offsets, water supply and water quality impacts, the timing of federal permits (*i.e.*, Endangered Species Act take permits), land use conflicts, public concerns, transmission line reliability and congestion, and natural gas availability. To gather information on these topics, the Commission conducted a series of workshops in the winter and spring of 2001. The following discussions summarize the nature of these constraints. The Staff's suggestions for alleviating the constraints are considered at the end of this chapter.

Emission Offsets

The new source review regulations contained in the Federal and California Clean Air Acts are administered by local air pollution control districts (air districts). New source review regulations require best available control technologies on new projects and reductions of emissions from other existing sources equal to or greater than emission increases from the new source (e.g., offsets). Existing offsets in most air districts are limited and/or expensive, and acquisition of offsets by power plant developers may reduce the offsets available to other industries, thereby increasing offset costs. Higher offset costs potentially reduce opportunities for economic growth in a community.

To date, all power plants approved have obtained the required offsets. Some of the emergency power plants and simple cycle power plants were permitted using an emission offset fee program, but this program sunsets in January 2003, and permanent offsets will need to be obtained to continue operation. Some power plant developers have pursued unconventional offsets, such as mobile emission reduction credits, area source emission reductions, inter-pollutant offsets, un-permitted sources, and offsets from up-wind adjoining air basins. Approving these unconventional offsets is difficult and time consuming since many air districts have not established rules and procedures to evaluate and approve emission offset credits generated by these measures.

Water Resources

Cooling Water

Power generation in California consumes about 235,000 acre-feet of water per year, representing about 0.3 percent of the total statewide consumption of 78 million-acre feet. Although the relative amount of water consumption by power plants is low, the Department of Water Resources predicts that the state-wide water shortfalls will increase and may total 2.4 million-acre feet annually by the year 2020. In addition, fresh water (including ground water) used for power plant cooling may have an adverse impact on local or regional water supplies needed for residential, agriculture, commercial, and industrial uses, and environmental protection. As California's population and water demands continue to grow, there will be increasing pressure for heavy industry, including power plants, to reduce fresh water use, and power plant developers are likely to find themselves competing with other users for diminishing supplies. If water for power plant cooling becomes unavailable or uneconomic, this will adversely effect the reliability and economics of the electricity system.

Once-Through Cooling

Approving new and upgrading existing power plants using once-through cooling is constrained by potential impacts to aquatic biological resources. New power plants must meet strict thermal discharge standards. The Federal Clean Water Act, Section 316(a), includes a provision stating that thermal standards can be waived as long as it is shown that balanced indigenous populations of fish, shellfish, and wildlife can be supported in the water body where the discharge occurs. However, completing the studies necessary to support that showing takes a substantial amount of time. Many coastal power plants using once-through cooling are currently operating under such exceptions, but it is not certain how or whether such exceptions can be applied to new or modified discharges needed for coastal power plant repowerings, refurbishments, or modernizations.

Federal Clean Water Act Section 316(b) requires the best technology available in terms of cooling technology. Since no currently adopted regulations specify how this is determined, the Regional Water Quality Control Boards have dealt with it on a case-by-case basis. The U.S. Environmental Protection Agency has proposed regulations for approving new and upgrading existing units or intake structures. The proposed regulations are fairly restrictive and would prohibit the use of once-through cooling in all circumstances except where the cooling water was drawn from the open ocean.

Timing of Federal Permits

Federal permits that address air quality and protect biological and water resources may be required for some projects. There is no requirement that Federal agencies issue their permits prior to or concurrent with the Energy Commission's power plant decisions. However, the Warren Alquist Act prohibits the Energy Commission from making "any finding in conflict with applicable federal law or regulation."[3] Consequently, federal agency participation in the Energy Commission's siting process provides the best possible assurance that the Energy Commission's actions are consistent with federal requirements.

A Biological Opinion (a Take Permit) is required under the Endangered Species Act if a project may impact an endangered species defined under the act. Projects that require a federal permit (i.e., have a federal nexus) are processes under Section 7, while projects that do not require a federal permit (no nexus) are processed under Section 10 of the act. Section 10 permits often take much longer to process than Section 7 permits. Consequently, if a developers proposal potentially impacts an endangered species, it is in the developer's interest to identify a federal nexus to ensure timely federal review.

Because California needs to license new power plants expeditiously, the timing of federal permits is critical. For the most part, federal agencies have been responsive to the state's needs for timely review of power plants, transmission lines, or gas pipelines. The federal agencies and Energy Commission staff have developed a cooperative working relationship that has facilitated the licensing of new power plants. However, as experienced in several recent cases, the timing of some federal permits may delay the licensing process. One problem has been appeals of air quality permits to the Environmental Appeals Board of the U.S. Environmental Protection Agency. These appeals, in some instances, have taken a substantial time to resolve. Recently, the Environmental Appeals Board has taken actions to expedite the review of these appeals, and major delays in construction have been avoided.

Land Use Conflicts and Public Participation

Land use conflicts often occur where proposed power plants create physical impacts such as traffic congestion, noise, dust, and visual impacts (e.g., light and glare). Power plants require substantial physical infrastructure that has become difficult to provide. Construction of extended new transmission facilities and other linear facilities often create land use conflicts and raise environmental concerns that are time consuming and expensive to resolve. Typically, land use compatibility issues are avoided by procuring sites that are large enough to provide an adequate buffer area, locating these sites within an existing industrial area, or locating sites so that intervening uses in the area would minimize land use conflicts.

Proposed new power plant projects may also be seen as counter to the economic development activities and goals of the local land use agency (cities or counties). For example, several cities and counties throughout California are actively pursuing large high technology high employee businesses to locate facilities in their industrial designated areas. They may perceive a proposed new power plant project as incompatible with these economic development goals. Other examples of this include perceived conflicts with the "quality of life" provided in a community.

An Executive Order, signed by President Clinton in 1994, directs federal agencies, and by extension state agencies, who receive federal funds, to identify and address any disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and/or low-income populations. The Energy Commission Staff conducts an analysis of the "environmental justice" impacts for each energy facility application.

Transmission Constraints

Although the Energy Commission licenses transmission lines needed to interconnect a power plant to the transmission system, other transmission projects are permitted by multiple agencies. The overlap, inconsistency and inefficiency created by such permitting pose potential constraints to expedited licensing of need electricity projects. Currently, depending on who the project proponent is, a transmission line project is subject to the regulatory review of one or more of the following:

- California Public Utilities Commission
- Energy Commission,
- Publicly Owned Utility
- City or County Planning Department
- Federal Agencies

Transmission projects are typically long linear facilities crossing multiple city and county boundaries. Normally, depending on the type of project proposed, one entity would function as the lead agency under CEQA. However, a project proposed by an independent power developer could have several lead agencies preparing separate environmental documents for those portions of the transmission line within their boundaries, if agreement cannot be reached on who should be the lead agency. This presents fundamental problems for both potential applicants and the state. First, multiple agency review is more costly and time-consuming for the independent power developers. Publicly Owned Utilities can function as their own lead agency under CEQA, and Investor Owned Utilities are subject solely to the jurisdiction of the California Public Utilities Commission. The state's interests in ensuring that the electrical supply system is as efficient and reliable as possible can be thwarted if needed transmission lines cannot be permitted in a timely manner or are not built due solely to local opposition.

Natural Gas Constraints

In October 2001 the Energy Commission published a report entitled *Natural Gas Infrastructure Issues*, which addresses the siting constraints associated with natural gas supply.

Towards Alleviating Constraints

In the November *2001 Staff Draft 2002-2012 Electricity Outlook Report*, the Staff recommended a variety of actions that could help alleviate the identified siting constraints. The Energy Commission restates these suggestions in this report and directs its Policy Committees, where they have jurisdiction, to consider implementing them, at their discretion. Where the suggestions involve significant Staff resources, the Executive Director will need to work the Policy Committees to address such internal constraints. Where the suggestions involve actions of outside entities, the Commission encourages those entities to consider the merits of the suggestions and to work with the Policy Committees and the Staff to help alleviate the constraints.

Emission Offset Constraints:

- Encourage offset trading markets, which will promote unconventional offset sources, increase offset availability, and lower costs for all offset market participants.

- Representatives of air districts, Air Resources Board, U.S. Environmental Protection Agency, and Energy Commission could meet to establish evaluation procedures and model regulations that could be used to permit unconventional emission reductions as emission offsets under air district new source review regulations. These agencies could continue to evaluate methods of generating offsets from the shutdown or over-control of existing power plants and other major sources. These agencies could also evaluate procedures and regulations that should be developed to implement these offset strategies.

- Energy Commission Staff could evaluate the adequacy of mitigation measures required by the California Environmental Quality Act based on whether the measures will have a substantial likelihood of eliminating or lessening the impacts of the project.

Water Supply Constraints:

- Energy Commission Staff could provide the Department of Water Resources with estimates of the existing and future needs for water for power plant cooling, to facilitate CDWR water resource planning efforts.

- Energy Commission Staff could work with Department of Water Resources and the State Water Resources Control Board to identify alternative sources of water for power plant cooling, including wastewater,, and contaminated or brackish ground water.

- Representatives of the Department of Water Resources, State Water Resources Control Board, and Energy Commission Staff could identify areas in the state where power plant development using fresh water should be discouraged, because of the projected critical short fall in fresh water supplies.

- The Energy Commission Staff could work with the Coastal Commission, Bay Conservation and Development Commission, Regional Water Quality Control Boards, State Water Resources Control Board, and California Department of Fish and Game to update the coastal siting study. That study could identify suitable sites for development, issues that must be addressed before approving future coastal power plant repowering projects, and identify the information that developers will need to obtain to license these projects.

- The Regional Water Quality Control Boards, State Water Resources Control Board, California Department of Fish and Game, and Energy Commission Staff could meet to evaluate state policies regarding the use of water for power plant cooling. These agencies could consider the long-term availability of water in California, the private and social costs of water use, the costs of alternative cooling technologies and cooling water sources, and the environmental impacts associated with fresh water use for power plant cooling in California. Any policies developed could provide guidance on their implementation and should encourage the uses of cooling technologies, such as dry or wet/dry cooling or alternative sources of cooling water, such as wastewater and brackish groundwater. The policies could also require the most efficient use of fresh water when its use is unavoidable. By reducing the state's demand for fresh water for power plant cooling, such policies could help maintain the reliability of the electricity system during emergencies and droughts.

Timing of Federal Permit Constraints:

- The Energy Commission could request that federal agencies identify a liaison to assure timely review of energy projects by the agency.

- The Energy Commission could request that federal agencies promptly identify the federal lead agency and nexus (i.e., the federal permits).

- Where both National Environmental Protection Act and CEQA reviews are required, the responsible agencies could enter into a memorandum of understanding that sets out a schedule for completing necessary environmental documentation and each agency's responsibilities, to avoid duplication of effort and expedite environmental review.

- The Energy Commission and federal and state agencies could meet to determine how to address growth-inducing impacts in their environmental documentation. Setting up agency-to-agency discussions to discuss how to handle growth-inducing impacts may prevent litigation of federal permits.

- The Department of Fish and Game's database of threatened and endangered species could be brought up to date and maintained. The database could be made publicly available to applicants so they can avoid impacts on endangered species or identify needed mitigation and, thus, avoid delays in obtaining permits.

- Federal and state agencies could establish habitat conservation banks. Perhaps the most time-consuming aspect of Endangered Species Act review is determining what mitigation conditions must be imposed. This might be facilitated by ready availability of habitat conservation banks.

Land Use Constraints:

- Before completing the data adequacy process for AFCs, the Energy Commission Staff could establish an early agency consultation process with local, regional, state and federal agencies potentially affected by proposed power plant projects to identify land use issues, compliance issues, and/or project alternatives.

- Once an application is accepted for review, the Energy Commission Staff could conduct workshops or information scoping meetings for land use agencies and the public regarding how the Energy Commission's power plant permitting process works and how the agencies and public can provide input.

- The Energy Commission could use information generated as part of its energy planning processes to educate local land use agencies. This might encourage them to consider the power needs of the community in their land use and planning activities, and as part of their general plan and specific plan development and update processes.

- The Energy Commission Staff could consider formatting Energy Commission meetings and workshops to provide for easy input and comment from the public and affected public agencies.

Transmission Constraints:

- The Energy Commission could support consolidation of transmission line permitting in California.

- The Energy Commission could support efforts to develop a state planning effort for new transmission lines to address congestion, system reliability and efficiency issues.

- The Energy Commission could direct the staff to examine the feasibility of an Energy Commission role in developing information on transmission congested locations in the state and use this information to inform siting applicants of advantageous siting locations.

- The Energy Commission Staff could coordinate with the CAISO and Participating Transmission Owners to explore potential locations for energy parks as siting locations for new generation facilities.

- The Energy Commission Staff could examine the feasibility of developing environmental information on alternative transmission rights-of-way for future transmission corridors identified in long-term grid planning studies.

Endnotes

1 California Code of Regulations, Title 20, § 1755 (b).
2 California Code of Regulations, Title 20, § 1741 (b)(3).
3 Public Resource Code §25525.

Appendix A-1
Megawatts, Unless Otherwise Indicated

	Statewide Resources				Statewide Outages			Statewide Net Resources	Statewide Net Reserve Margin (%)
	Thermal	Hydro	Firm Imports	Total Resources	Scheduled	Hydro Derate	Total Outages		
Jan-02	44,249	13,247	2,412	59,908	(2,989)	(2,500)	(5,489)	54,419	38%
Feb-02	44,254	13,252	2,412	59,918	(3,964)	(2,500)	(6,464)	53,454	39%
Mar-02	45,410	13,253	2,309	60,972	(5,136)	(2,500)	(7,636)	53,336	40%
Apr-02	45,632	13,257	2,309	61,198	(5,832)	(2,500)	(8,332)	52,866	34%
May-02	45,614	13,276	2,209	61,099	(4,664)	(2,500)	(7,164)	53,935	27%
Jun-02	45,757	13,313	3,007	62,077	(325)	(1,500)	(1,825)	60,252	23%
Jul-02	45,740	13,329	3,007	62,075	(325)	(1,500)	(1,825)	60,250	15%
Aug-02	46,161	13,332	3,007	62,500	0	(1,500)	(1,500)	61,000	12%
Sep-02	46,119	13,294	3,125	62,537	0	(1,500)	(1,500)	61,037	18%
Oct-02	45,943	13,238	2,302	61,483	(1,583)	(2,500)	(4,083)	57,400	30%
Nov-02	45,983	13,238	2,412	61,634	(4,293)	(2,500)	(6,793)	54,841	37%
Dec-02	45,979	13,233	2,412	61,624	(2,938)	(2,500)	(5,438)	56,186	36%
Jan-03	45,715	13,247	2,412	61,374	(2,989)	(2,500)	(5,489)	55,885	38%
Feb-03	45,720	13,252	2,412	61,384	(3,964)	(2,500)	(6,464)	54,920	40%
Mar-03	45,766	13,253	2,309	61,327	(5,136)	(2,500)	(7,636)	53,691	37%
Apr-03	45,586	13,257	2,309	61,152	(5,832)	(2,500)	(8,332)	52,820	31%
May-03	45,415	13,276	2,209	60,899	(4,664)	(2,500)	(7,164)	53,735	23%
Jun-03	46,128	13,313	3,007	62,447	(325)	(1,500)	(1,825)	60,622	21%
Jul-03	46,860	13,329	3,007	63,195	(325)	(1,500)	(1,825)	61,370	15%
Aug-03	46,832	13,332	3,007	63,170	0	(1,500)	(1,500)	61,670	11%
Sep-03	46,290	13,294	3,125	62,709	0	(1,500)	(1,500)	61,209	16%
Oct-03	43,953	13,238	2,302	59,493	(1,583)	(2,500)	(4,083)	55,410	23%
Nov-03	44,423	13,238	2,412	60,073	(4,293)	(2,500)	(6,793)	53,280	30%
Dec-03	44,767	13,233	2,412	60,412	(2,938)	(2,500)	(5,438)	54,974	30%

Appendix A-2
Annual Average Natural Gas Prices
2000 $ per Mcf

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
PG&E	3.09	3.16	3.22	3.28	3.34	3.40	3.47	3.54	3.61	3.69	3.76
SoCal Gas/ San Diego	2.94	3.00	3.06	3.16	3.25	3.33	3.41	3.48	3.56	3.63	3.70
So. Calif Prod.	2.85	2.946	3.042	3.138	3.234	3.33	3.406	3.482	3.558	3.634	3.71
TEOR/Coolwater	3.05	3.128	3.206	3.284	3.362	3.44	3.514	3.588	3.662	3.736	3.81
Alberta	2.55	2.596	2.642	2.688	2.734	2.78	2.828	2.876	2.924	2.972	3.02
British Columbia	2.72	2.782	2.844	2.906	2.968	3.03	3.094	3.158	3.222	3.286	3.35
Colorado	2.99	3.03	3.06	3.10	3.13	3.17	3.21	3.26	3.30	3.35	3.39
El Paso N & S AZ/NM	2.78	2.88	2.98	3.07	3.17	3.27	3.36	3.45	3.53	3.62	3.71
Kern River	2.90	2.96	3.02	3.09	3.15	3.21	3.30	3.39	3.48	3.57	3.66
Mojave	2.97	3.04	3.12	3.19	3.27	3.34	3.42	3.51	3.59	3.68	3.76
Montana	2.93	2.98	3.03	3.07	3.12	3.17	3.21	3.26	3.30	3.35	3.39
Nev-No	3.08	3.14	3.20	3.25	3.31	3.37	3.44	3.50	3.57	3.63	3.70
Nev-So	3.22	3.30	3.38	3.47	3.55	3.63	3.71	3.78	3.86	3.93	4.01
PGT-Kingsgate	2.28	2.33	2.38	2.42	2.47	2.52	2.57	2.62	2.66	2.71	2.76
PGT-Malin	2.66	2.72	2.78	2.84	2.90	2.96	3.03	3.10	3.17	3.24	3.31
PGT-Stansfield	2.47	2.52	2.57	2.61	2.66	2.71	2.77	2.83	2.88	2.94	3.00
PNW	3.52	3.58	3.64	3.71	3.77	3.83	3.88	3.93	3.99	4.04	4.09
PNW-Coastal	2.76	2.83	2.90	2.96	3.03	3.10	3.16	3.23	3.29	3.36	3.42
Utah	2.99	3.03	3.06	3.10	3.13	3.17	3.21	3.25	3.30	3.34	3.38
Rosarito	2.91	2.99	3.06	3.14	3.21	3.29	3.37	3.45	3.53	3.61	3.69
Otay Mesa	2.92	3.00	3.08	3.16	3.23	3.31	3.39	3.47	3.54	3.62	3.70

Appendix A-2
Monthly Natural Gas Price Multpliers

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PG&E	1.06	1.06	0.99	0.97	0.99	0.96	0.96	0.96	0.96	0.96	1.05	1.09
Southern California*	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
SDG&E/ Rosarito/ Otay Mesa	1.09	1.04	0.96	0.94	1.00	0.97	0.92	0.97	0.98	0.98	1.09	1.22
Coolwater	1.08	1.05	1.02	0.97	0.96	0.94	0.93	0.94	0.97	0.99	1.08	1.19
Alberta	0.99	1.08	1.00	1.04	0.99	0.93	0.94	0.87	0.91	1.00	1.08	0.97
British Columbia	1.23	0.97	0.88	0.93	0.87	0.83	0.82	0.83	0.87	1.00	1.21	1.36
Colorado	1.05	0.94	0.85	0.88	1.12	0.88	1.07	1.03	0.89	0.92	1.09	1.20
El Paso N & S - AZ	1.07	0.99	1.07	1.28	1.07	0.93	0.90	1.04	0.93	1.10	1.11	1.17
El Paso N & S - NM	1.18	1.02	0.97	0.96	0.97	0.94	0.97	0.96	0.94	1.00	1.11	1.14
Montana	1.38	1.67	1.45	1.28	1.07	1.20	0.83	0.72	0.78	0.81	0.97	1.20
NV - N & S	1.03	1.01	0.95	1.01	0.97	1.02	0.93	0.98	0.99	1.09	1.13	0.98
PGT-Malin/ PGT-Stansfield	1.15	1.12	1.06	0.94	0.84	0.95	0.92	0.90	0.87	0.99	1.13	1.16
PNW/ PNW Coastal/ PGT - Kinsgate	0.68	0.83	1.00	1.27	1.35	0.76	1.01	1.00	1.11	0.90	0.96	1.09
Utah	1.38	1.67	1.45	1.28	1.07	1.20	0.83	0.72	0.78	0.81	0.97	1.20

Appendix A-2
GDP Implicit Price Deflator
(2001 = 100)

Year	Deflator	Increase
2001	100.00	
2002	101.64	1.6%
2003	103.20	1.5%
2004	104.94	1.7%
2005	106.97	1.9%
2006	109.39	2.3%
2007	112.12	2.5%
2008	115.07	2.6%
2009	118.25	2.8%
2010	121.71	2.9%
2011	125.50	3.1%
2012	129.65	3.3%

Appendix A-3

Reliability, Environmental, and General Criteria

Reliability Criteria, in Order of Decreasing Importance

Forced outage rate (EFOR Value):
This is the percentage of time that a plant is unavailable because of equipment failure. The higher the forced outage rate, the more likely the unit will be unexpectedly out of service when needed. Forced outage rate is deemed to be the most important reliability criterion, because the higher the forced outage rate, the less the state can count on the unit to be ready when called upon.

Capacity Factor (Cap Value):
This is the amount of electricity a unit generates, as a fraction of the total amount it is capable of generating in a year. The capacity factor is deemed to be the next most important reliability criterion. Plants that run the most often are usually those with lower costs, in good physical condition, and have fewer operating constraints.

Maintenance Outage Rate (MOR Value):
This is the percentage of time that a plant is unavailable because of planned maintenance work. The higher the maintenance outage rate, the more often the unit is unavailable due to planned shutdowns. The maintenance outage rate is not as important as the forced outage rate, because the California Independent System Operator (ISO) has an opportunity to schedule replacement capacity for these shutdowns. Nonetheless, a high MOR implies that, for reliability purposes, a plant will be available less often.

Dependable Capacity (DC Value):
This indicates the unit's generation potential. The greater the dependable capacity, the greater the contribution to system reliability a plant may make. If a plant is old and in poor condition, however, dependable capacity is irrelevant. Staff has chosen to include it in this study, however, because the state needs to think carefully about reserve margins before considering any retirements.

Transmission Constrained (Trans Score); Generation Deficient (GD Value):
These two criteria give an indication of the strategic position of plants within the state. Transmission-constrained areas must rely heavily on local generation to meet power needs, because of a shortage of capacity on transmission lines to import power when needed. Staff identified the Bay

Area and San Diego as transmission-constrained areas. Generation-deficient areas include RMR areas that lack sufficient generation to meet expected demand in 2002. The reliability of units in generation-deficient and transmission-constrained areas is of higher importance than that of units in areas suffering from neither condition. Generation deficiency ranks slightly above transmission constraints because generation-deficient areas are more likely to sustain low reserve margins in 2004, which would militate against retiring a unit. One can retire a unit in a transmission-constrained area, though, provided the area has a sufficient reserve margin.

Age (Age Value):

A unit's age is important because the older it is, the more likely it will require costly maintenance. However, other criteria (maintenance expenditures; e.g. Moss Landing) mitigate the importance of age.

Reliability Must-Run Contract (RMR):

Turbines designated by the ISO as RMR units. Following this designation, the unit's owner is eligible to negotiate with the ISO to have the unit available for dispatch by the ISO during times when grid reliability can be maintained only if the unit is run.

Environmental Criteria

Cooling Method (Cooling Value):

This refers to the method used to condense steam from a boiler unit. Thermal units may use either once-through cooling, wet cooling towers, or dry cooling. The method a plant chooses helps determine the amount of water it will use in generating electricity and how aquatic life will be affected by the plant's operations.

Water Source (Water Value):

Plants use water from oceans, bays, lakes and rivers, groundwater, or waste water. Because fresh water is a more limited resource with broad public uses, society would prefer that a unit use ocean water or wastewater for cooling purposes.

NO_x Emissions (NO_x Value)

This gives the amount of NO_x emitted per kilowatt-hour of electricity generated when the unit operates at full load. Because NO_x is a precursor to ozone, an air pollutant that has been shown to be a potential public health threat, staff deems this to be an important environmental criterion.

Other Identifying Criteria

Unit Type

Fossil-fueled turbines are designed as either a utility boiler (UB) powering a steam turbine; combustion turbines, or "peakers," including gas turbines (GT) and oil-fired turbines (OT); and combined-cycle units (CC)

Air Pollution Control District (Air District):

The air pollution control or air quality management district in which the unit is located.